E L E C T R I C O R E , I N C .
The Consortium for Advanced Technologies
27943 Smyth Drive, Suite 105
Valencia, CA 91355
Phone: (661) 607-0260
Fax: (661) 607-0264
www.electricore.org

August 9, 2006

Mr. Blaine Keener
Technical Manager
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Washington, D.C. 20590

RE: Pipeline Safety Research and Development Other Transaction Agreement DTPH56-05-T-0003 153H – Draft Final Report

Dear Mr. Keener:

Please see the attached draft final report for the project "Corrosion Assessment Guidance For Higher Strength Steels" conducted by Electricore, Advantica, and Pipeline Research Council International (PRCI).

This draft is currently being reviewed by PRCI's technical committee members. Comments and revisions from this review process will be incorporated into the final document and submitted to the DOT.

If you have any questions regarding this draft report, or require additional information please contact me at 661-607-0261.

Thank you,

Ian C. Wood
Program Manager
Electricore, Inc.

ADVANTICA

R9017 Draft *August 2006*

PROJECT #153H
CORROSION ASSESSMENT GUIDANCE FOR HIGHER STRENGTH STEELS

Confidential *Restricted to, Electricore/PRCI/DOT & Advantica*

PREPARED FOR:

J Merritt, US DOT Office of Pipeline Safety

M Smith, Pipeline Research Council International, Inc.

PREPARED BY:
V Chauhan and J Crossley

Advantica
Ashby Road
Loughborough Leicestershire
LE11 3GR
United Kingdom
Tel: +44 (0)1509 282363
Fax: +44 (0)1509 283119
E-mail: vinod.chauhan@advantica.biz
Website: www.advantica.biz

STONERSOFTWARE

Report Issue Record

Report Title: Corrosion Assessment Guidance for Higher Strength Steels	
Report Number: R 9017	**Project SAP Code: 1/07620**

Issue	Description of Amendment	Originator/Author	Checker	Approver	Date
Draft	Draft for Customer Comment	J Crossley, V Chauhan	V Chauhan	V Chauhan	August 2006

Previous issues of this document shall be destroyed or marked **SUPERSEDED**

ADVANTICA

Distribution

Name	Company
B Keener	US DOT Office of Pipeline Safety
J Merritt	US DOT Office of Pipeline Safety
R Smith	US DOT Office of Pipeline Safety
M Smith	Pipeline Research Council International, Inc.
R Owen	National Grid plc
N Sanderson	BP Exploration
Ian Wood	Electricore, Inc.

Recipients of this page may obtain a copy of this report from:
Advantica, Ashby Road, Loughborough,
Leicestershire, LE11 3GR. Telephone 01509 282000 Facsimile 01509 283131

Executive Summary

The continuing worldwide demand for natural gas presents major challenges to pipeline operators. There is increasing need to construct long distance, high capacity transmission pipelines, particularly in the more remote areas of Arctic North America, Asia, Africa and South America. To achieve satisfactory economic returns on the investment, operators are focusing attention on the use of increasing material strength (pipe grade), thus reducing both the total steel tonnage, transportation costs and the volume of weld metal needed to be applied during pipe installation. Alternatively, the use of higher material strengths can also allow higher operating pressures and smaller pipe diameter. Steel making and pipe manufacturing developments during the 1970's and 1980's resulted in the progressive evolution of API5L Grade X65 to X70 and X80. In North America and Europe, X80 pipelines have gained general acceptance. The economic benefits of further increases in strength have focused attention on the next step increase to Grade X100 and even X120.

Extensive experimental and numerical work has been undertaken to develop methods for assessing the remaining strength of corroded transmission pipelines. These methods, embodied in documents such as ASME B31G [1], RSTRENG [2, 3] and LPC [4] have, however, only been validated for pipeline materials of grades up to and including X65. As operators start to use higher material strengths, there will be an increasing need to assess the integrity of corroded pipelines. Use of existing assessment methods may be inappropriate for higher strength pipelines. A particular concern is the high yield to tensile (Y/T) ratio of high strength steels; early development X100 materials had Y/T values up to 0.98. Although more recent materials have reduced this to some extent, there is still a concern that high strength steels may not have sufficient work hardening capacity, or strain to failure, to ensure that existing assessment methods are appropriate.

This report describes a program of work to extend existing methods to material strengths up to grade X100 using finite element (FE) analyses and validation using full scale testing.

Conclusions

1 The ASME B31G and RSTRENG methods can give non-conservative failure predictions when assessing the remaining strength of higher strength (grade X80 and X100) corroded pipelines.

2 The LPC-1 method is the most accurate method for assessing the remaining strength of corroded higher strength (up to X100) pipelines. However, LPC-1 can give non-conservative failure predictions.

3 The non-linear FE method used to predict the failure pressure is valid for higher strength steels up to grade X100.

4 The LPC-1 method, with the flow stress modified to equal the average of the specified minimum yield and ultimate tensile strength, predicts conservative failure pressures for corroded pipelines of grades up to X100.

Recommendations

1. The remaining strength of corroded pipe of grade higher than X65 should be assessed using the LPC-1 method but with the flow stress modified to be equal to the average of the specified minimum yield and ultimate tensile strength.
2. Further testing and assessment is undertaken to validate the method by investigating the sensitivity to pipe (*D/t*) ratio and defect shape.
3. The assessment method should be extended to cover defect interaction and external secondary loading.

Contents

NOMENCLATURE

D	Pipe Diameter
t	Pipe wall thickness
L	Defect length
d	Defect depth
σ_{smys}	Specified Minimum Yield Strength
σ_{smts}	Specified Minimum Tensile Strength
σ_{flow}	Flow stress
R_s	Remaining Strength Factor
M	Folias (bulging correction) factor
P_o	Predicted failure pressure for defect free pipe calculated using the flow stress
P_f	Predicted failure pressure of corroded pipe

1 INTRODUCTION

The continuing worldwide demand for natural gas presents major challenges to pipeline operators. There is increasing need to construct long distance, high capacity transmission pipelines, particularly in the more remote areas of Arctic North America, Asia, Africa and South America. To achieve satisfactory economic returns on the investment, operators are focusing attention on the use of increasing material strength (pipe grade), thus reducing both the total steel tonnage, transportation costs and the volume of weld metal needed to be applied during pipe installation. Alternatively, the use of higher material strengths can also allow higher operating pressures and smaller pipe diameter. Steel making and pipe manufacturing developments during the 1970's and 1980's resulted in the progressive evolution of API5L Grade X65 to X70 and X80. In North America and Europe, X80 pipelines have gained general acceptance. The economic benefits of further increases in strength have focused attention on the next step increase to Grade X100 and even X120.

Extensive experimental and numerical work has been undertaken to develop methods for assessing the remaining strength of corroded transmission pipelines. These methods, embodied in documents such as ASME B31G [5], RSTRENG [6, 7] and LPC [8] have, however, only been validated for pipeline materials of grades up to and including X65. As operators start to use higher material strengths, there will be an increasing need to assess the integrity of corroded pipelines. Use of existing assessment methods may be inappropriate for higher strength pipelines. A particular concern is the high yield to tensile (Y/T) ratio of high strength steels; early development X100 materials had Y/T values up to 0.98. Although more recent materials have reduced this to some extent, there is still a concern that high strength steels may not have sufficient work hardening capacity, or strain to failure, to ensure that existing assessment methods are appropriate.

This report describes a program of work to extend existing methods to material strengths up to grade X100 using finite element (FE) analyses and validation using full scale testing.

2 CURRENT ASSESSMENT METHODS

Existing assessment methods regularly used by the pipeline industry are ASME B31G [5], RSTRENG [6, 7], LPC [8], BS 7910 [9] and DNV RP-F101 [10]. The refinery and petrochemical industry also use API RP 579 [11]. These methods have been developed from the results of a large number of full-scale burst tests on ring expansion and vessel specimens. Some researchers have supplemented their database of full-scale test results with finite element (FE) analyses. A wide range of material properties and pipeline geometries has been investigated. Most of the experimental work considered volumetric corrosion defects, predominantly longitudinally-orientated, subject to internal pressure, but the effect of in-plane bending and axial loading has also been studied. Some tests have also been undertaken on pipes with circumferentially or helically orientated corrosion defects. In the US, CFR 192 [8] and 195 [9] recommends using only ASME B31G or RSTRENG.

A brief background to the development of each assessment method is described below.

2.1 ASME B31G Method

Much of the original work to develop assessment methods for damaged pipelines was conducted at the Battelle Memorial Institute located in the United States of America (USA) under the NG-18 research programme, sponsored by Pipeline Research Council International, Inc. (PRCI). The research was initially concentrated on the behavior of sharp defects (machined V-shaped notches and slits), but subsequently the work was extended to consider real corrosion defects in pipelines. This research formed the background to a method for assessing corrosion defects, which was subsequently incorporated into a supplement to ASME B31 code for pressure piping for determining the remaining strength of corroded pipelines. The guidance is codified as ASME B31G [5] for assessing axially orientated, through-wall and part-wall defects in a cylindrical pipe subject to internal pressure loading. The failure criterion is based on an empirical fit to 47 full-scale tests on vessels containing narrow machined slots. The tests generally involved severely corroded lengths of pipe removed from service after a number of years of operation, supplied by several US gas pipeline companies.

The range of the experimental parameters studied is summarized in Table 1. Briefly, the ASME B31G method has been validated for material grades A25 to X52; diameters ranging from 16 inch (406.4mm) to 30 inch (762mm) and pipe (*D/t*) ratios of 51.3 to 81.1.

The failure pressure, P_f, of a corroded pipe calculated according to the ASME B31G method can be determined using Equation (1) to (5).

$$P_f = P_o R_s \tag{1}$$

where

$$P_o = \frac{2\sigma_{flow}}{\left(\frac{D}{t}\right)} \tag{2}$$

$$\sigma_{flow} = 1.1\sigma_{smys} \tag{3}$$

$$R_s = \frac{1-\frac{2}{3}\left(\frac{d}{t}\right)}{1-\frac{2}{3}\left(\frac{d}{t}\right)\frac{1}{\sqrt{1+0.8\left(\frac{L}{\sqrt{Dt}}\right)^2}}} \quad \text{for} \quad \left(\frac{d}{t}\right)\le 0.8 \text{ and } \frac{L}{\sqrt{Dt}} \le 4.479 \tag{4}$$

and

$$R_s = 1-\left(\frac{d}{t}\right) \quad \text{for} \quad \left(\frac{d}{t}\right)\le 0.8 \text{ and } \frac{L}{\sqrt{Dt}} > 4.479 \tag{5}$$

where D = Pipe Outside Diameter

t = Wall Thickness

d = defect depth

L = defect length

P_o = predicted failure pressure for defect free pipe calculated using the flow stress

R_s = Remaining Strength Factor

σ_{flow} = Flow stress

σ_{smys} = Specified Minimum Yield Strength

2.2 RSTRENG Method

From its inception, the ASME B31G method was intended to embody a large factor of safety to protect pipelines from failure. Use of the method has shown that the amount of conservatism embodied in the criterion can be excessive, resulting in the removal or repair of more pipe than is necessary to maintain adequate integrity. Through funding from PRCI, the RSTRENG method [6, 7] was developed to reduce the level of known conservatisms in the ASME B31G method while still ensuring an adequate level of pipeline integrity. The sources of conservatism in the ASME B31G method cited in [6] include the definition of the flow stress (σ_{flow}); the Folias Factor, M; and the parabolic representation of the metal loss.

The original body of data of 47 burst tests of corroded pipe that was used to validate the ASME B31G criterion was expanded by an additional 39 test results obtained from pipeline companies who had performed their own burst tests. The expanded database of 86 test results demonstrated that the RSTRENG method (sometimes referred to as the modified ASME B31G method) showed an adequate margin of safety.

Further validation of the method was undertaken by the inclusion of the results of a further 129 tests. These results were subsequently collated in a test database of corroded pipe test results maintained by the American Gas Association (AGA) and PRCI [4]. The range of the experimental parameters used to validate the RSTRENG method is summarized in Table 2. Briefly, the test database has been extended to cover material up to grade X65; the pipe diameter has also been extended to cover the range 10¾ inch (273mm) to 48 inch (1219.2mm) and pipe (D/t) ratios in the range 40.6 to 130.3.

The failure pressure, P_f, of a corroded pipe according to the RSTRENG method can be determined using Equation (6) to (10) below:

$$P_f = P_o R_s \tag{6}$$

$$P_o = \frac{2\sigma_{flow}}{\left(\frac{D}{t}\right)} \tag{7}$$

$$\sigma_{flow} = \sigma_{smys} + 10{,}000 \text{ (psi)} \tag{8}$$

$$R_s = \frac{1 - 0.85\left(\frac{d}{t}\right)}{1 - 0.85\left(\frac{d}{t}\right)\frac{1}{\sqrt{1 + 0.6275\left(\frac{L}{\sqrt{Dt}}\right)^2 - 0.003375\left(\frac{L}{\sqrt{Dt}}\right)^4}}} \text{ for}$$

$$\left(\frac{d}{t}\right) \le 0.8 \text{ and } \frac{L}{\sqrt{Dt}} \le 7.071 \tag{9}$$

$$R_s = \frac{1 - 0.85\left(\frac{d}{t}\right)}{1 - 0.85\left(\frac{d}{t}\right)\frac{1}{\left[3.3 + 0.032\left(\frac{L}{\sqrt{Dt}}\right)^2\right]}} \text{ for}$$

$$\left(\frac{d}{t}\right) \le 0.8 \text{ and } \frac{L}{\sqrt{Dt}} > 7.071 \tag{10}$$

2.3 BS 7910

The Linepipe Corrosion (LPC) Group Sponsored Project which was led by Advantica (then part of British Gas) undertook a program of 81 full scale vessel burst tests and 52 ring expansion tests on simulated corrosion defects in linepipe subject to internal pressure. The tests included isolated, interacting and complex shaped corrosion defects that were machined either as pits, grooves or patches on the surface of the pipe. The pipe geometries tested included diameters from 8⅝ inch (219mm)[1] to 36 inch (914.4

[1] 7 tests were undertaken on Grade X52 pipe with wall thicknesses ranging from 24.5mm to 25.4mm. All vessels contained external groove defects with a (d/t) ratio range 0.2 to 0.94. Deeper defects resulted in

mm); pipe (D/t) ratios from 8.6 to 47.9, and materials from grade X52 to X65. The full test data has not been fully published in the public domain; a general summary of the limited results is presented in [8]. Full details are contained in a BG Technology (now Advantica) report prepared for sponsors of the project [12]. All of the tests of blunt machined defects failed in a manner consistent with failure controlled by plastic collapse (necking of the remaining ligament leading to geometric instability and failure). On the completion of the group sponsored project, the method was released to BSi for inclusion in BS 7910. The range of the experimental parameters used to validate the BS 7910/LPC method is summarized in Table 3.

Extensive three-dimensional, non-linear, elastic-plastic finite element (FE) analyses of the failure of blunt metal loss defects in closed-ended cylinders subject to internal pressure were also undertaken using ABAQUS/Standard. Detailed guidance for the assessment of corrosion in line pipe was subsequently developed, based on the results of the FE and experimental studies. These studies led to the development of the assessment method that is now incorporated into Annex G of BS 7910 [9]. Guidance is given for the assessment of isolated corrosion defects; for the assessment of closely spaced corrosion defects that may interact and for the assessment of a corrosion defect using a river-bottom profile. The assessment of an isolated corrosion defect is based on the same underlying methodology developed as part of the original NG-18 research programme, but the Folias factor, M, is modified based on the results of parametric finite element study. The flow stress, σ_{flow}, is taken as being equal to the ultimate tensile strength, based on the observation that the tensile strength better describes failure controlled by plastic collapse.

The failure pressure, P_f, of an isolated corrosion defect in a pipe according to Annex G of BS 7910 can be determined using Equations (11) to (14) below:

$$P_f = P_o R_s \qquad (11)$$

$$P_o = \frac{2\sigma_{flow}}{\left(\frac{D}{t} - 1\right)} \qquad (12)$$

$$\sigma_{flow} = \sigma_{smts} \qquad (13)$$

$$R_s = \frac{1 - \left(\frac{d}{t}\right)}{1 - \left(\frac{d}{t}\right)\frac{1}{\sqrt{1 + 0.31\left(\frac{L}{\sqrt{Dt}}\right)^2}}} \quad \text{for} \quad \left(\frac{d}{t}\right) \le 0.85 \text{ and all lengths} \qquad (14)$$

---

failure of the vessel as a leak. Failure of the vessel by rupture was obtained for defect (d/t) ratios in the range 0.5 to 0.72. Failure pressures ranged from 685 bar to 1241 bar.

where

σ_{smts} = Specified Minimum Tensile Strength

Note that in contrast to ASME B31G and RSTRENG methods, this approach defines the flow stress using the specified minimum *tensile* strength rather than yield strength, as this was found to give more accurate predictions.

The intent of the guidance given in BS 7910 is to provide simplified, conservative procedures for the assessment of corroded pipelines or pressure vessels. If the corrosion defects are found to be unacceptable using the procedures given then the user has the option of considering an alternative course of action. This could include, but is not limited to, detailed finite element (FE) analysis and/or full scale testing. Recommendations for conducting non-linear FE analysis to determine safe operating pressures of corroded pipelines and pressure vessels are described in Annex G of BS 7910.

2.4 DNV RP-F101

The results of the Linepipe Corrosion Project were merged with those of a similar project conducted by Det Norske Veritas (DNV). This resulted in the development of a Recommended Practice, DNV RP-F101 [10]. The DNV project generated a database of 12 burst tests on pipes containing machined corrosion grooves, primarily to develop guidance for assessing combined internal pressure and external loading The recommended practice contains guidance for the assessment of isolated corrosion defects; for the assessment of adjacent corrosion defects that may interact and for the assessment of a corrosion defect using a river-bottom profile, all considering internal pressure loading only, and guidance for the assessment of isolated corrosion defects subject to internal pressure and external loads. Guidance for assessing isolated and interacting defects is based on the same approach as that developed for BS 7910. The recommended practice consists of two parts; Part A is based on the Load and Resistance Factor Design format and makes use of the concept of partial safety factors, Part B is based on the Allowable Stress Design format and makes use of a single safety factor.

2.5 API RP 579

API RP 579 provides guidelines for performing fitness for service (FFS) assessments that can be used for assessing damage mechanisms of the type found in the refining and petrochemical industries. The assessment methods in API RP 579 were originally developed to assess pressure equipment designed and constructed to US codes used in the petrochemical industry, in particular the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 and 2 [13], the power and chemical piping codes ASME B31.1 [14] and ASME B31.3 [15], and the tank codes API 650 [16] and API 620 [17]. It is not, at present, specifically intended for application to pipelines.

API RP 579 describes methods for the assessment of general metal loss, local metal loss and pitting corrosion. General metal loss is not precisely defined, but can be considered to represent metal loss due to corrosion (or erosion) over a large area of the structure. Note that API RP 579 gives procedures for assessing the fitness-for-purpose of a variety of different types of defect in pressurized components such as pressure vessels, piping and storage tanks. It does not specifically address pipelines. The underlying approach is, however, based on the ASME B31G and RSTRENG methods. The API RP 579 criterion has been modified and interpreted in terms of a remaining strength factor (RSF). The authors of the recommended practice have also modified the Folias factor, M. The API RP 579 criterion was compared with a database of test results compiled from the public domain. This database was primarily obtained from PRCI [18] and included pipe diameters in the range 16 inch (406.4mm) to 36 inch (914.4mm); wall thickness from 0.198 (5mm) to 0.444 inch (11.3mm) and material strength grades A to X65. Failure pressures in the database ranged from 48 bar to 145 bar. The resulting assessment method is claimed to reduce the level of conservatism when compared to ASME B31G and RSTRENG.

Two types of local metal loss are defined: a locally thin area (LTA) and a groove-like flaw. A locally thin area is local metal loss on the surface of the component with length and width of the same order of magnitude. Two types of groove-like flaw are described: (1) a groove, which is defined as a local elongated thin spot caused by directional erosion or corrosion, with *a*, the length significantly greater than the width, and (2) a gouge, which is defined as elongated local mechanical removal of material from the surface of a component, causing a reduction in wall thickness; the length of a gouge is much greater than the width and the material may have been cold worked. It is noted that a sharp radius may be present at the base of a groove-like flaw. A significant groove-like feature, requiring a more detailed assessment, is defined as one with a groove radius less than the greater of either 25% of the required thickness or 6.4 mm (0.25 inch).

Pitting is defined as localized regions of metal loss which can be characterized by a pit diameter less than or equal to the plate thickness (t). Four types of pitting are described: widely scattered pitting occurring over a significant region of a structure, a LTA located in a region of widely scattered pitting, localized regions of pitting, and pitting confined to an LTA.

Three assessment levels are described in the document. A simple Level 1 criterion is given based on the defect length and depth dimensions and a more complex Level 2 criterion which can be used on the basis that a detailed cross-sectional profile of the defect is available. A Level 3 assessment using non-linear finite element stress analysis is also described, similar to the approach described in Annex G of BS 7910.

2.6 Battelle-Shannon Method

The Battelle-Shannon equation [19] is a semi-empirical relationship for determining the failure strength of linepipe materials containing part-wall metal loss defects such as gouges, general corrosion and pitting corrosion. The equation was developed by

Battelle and British Gas in the early 1970's and was validated against 92 burst tests on vessels with the following range of geometric and materials parameters,

- Pipe diameters (D) up to 48"
- Pipe wall thicknesses (t) up to 21.9mm
- Pipe D/t ratios from 26 to 104
- Defect depth to wall thickness ratio (d/t) up to 0.92
- Material strength up to grade X65.

The failure strength (σ_{fail}) of a part-wall metal loss defect is given by the following equation,

$$\sigma_{fail} = \sigma_{flow}\left[\frac{1-\frac{d}{t}}{1-\frac{d}{t}\left(\frac{1}{M}\right)}\right] \qquad (15)$$

$$M = \sqrt{1+0.26\left(\frac{2c}{\sqrt{Rt}}\right)^2} \qquad (16)$$

where d = defect depth

t = pipe wall thickness

R = pipeline outside radius

2c = defect length

σ_{flow} = 1.15 x SMYS

The failure pressure P_f, can then be calculated from,

$$P_f = \sigma_{fail}\frac{20t}{D} \qquad (17)$$

For an infinitely long part-wall metal loss defect the failure strength can be calculated using the following equation,

$$\sigma_{fail} = \sigma_{flow}\left[1 - \frac{d}{t}\right] \tag{18}$$

The corresponding failure pressure can then be calculated by substituting Equation (18) into Equation (17).

2.7 PRCI Review

The Line Pipe Research Supervisory Committee of PRCI commissioned a project in 2000 with Advantica (then BG Technology), Battelle Memorial Institute and Shell Global Solutions to critically review a number of existing and newly emerging methods for assessing corroded pipelines [20]. As part of this review, an integrated database of 256 tests on corroded pipe was produced. Test results from four major sources were reviewed and collated in the database. The first source is the PRCI database of 124 tests, compiled in 1994 [18], the second source is a database of 20 tests published by University of Waterloo [21], the third source is a database of 33 tests produced by Advantica in 1992 [22], [23] and the fourth source is a database of 79 tests produced by Advantica for the group sponsored project on line pipe corrosion during 1994-1997 [12].

Figures 1 and 2 show the distribution of pipe grade and (*D/t*) ratio contained in the overall database. There are almost 50 tests undertaken on grade X65 pipe.

The general conclusions drawn from the review were as follows:

- The ASME B31G and RSTRENG equations generally give conservative failure predictions for the corroded pipe tests. However, they can give non-conservative failure predictions for deep defects. Failure predictions using the ASME B31G equation gives the largest scatter. The RSTRENG equation gives relatively consistent and less conservative failure predictions.
- The LPC (BS 7910/DNV RP-F101) equation is generally less conservative, and gives more accurate failure predictions than both the ASME B31G and RSTRENG equations. Some non-conservative predictions were recorded for older grade B pipe.

3 APPROACH

The level 3 non-linear FE method described in BS 7910 and API RP 579 has been successfully used by Advantica to predict the failure pressure of corroded pipelines. The method has been shown to consistently predict the failure pressure of corroded pipe. In agreement with the PRCI project team, the approach taken was as follows:

1. A series of level 3 (non-linear FE) analyses are undertaken by selecting a common pipe (*D/t*) ratio and varying stress versus strain data for pipe material grades X65, X80 and X100. This approach would then allow the sensitivity of predicted failure pressure to be determined with increasing material grade.

2. Validate the failure pressure predictions using available burst test data. It is, however, to be noted that very little data has been published in the public domain on the failure behavior of corroded grade X100 line pipe. Advantica has undertaken a separate project on behalf of BP Exploration to investigate the failure behavior of corroded 52-inch grade X100 line pipe [24]. BP Exploration has agreed to release the results of this test program to validate the results of the FE analyses. A brief description of the test program and results is described in section 4 below.

3. Compare the burst test data, with failure predictions obtained from FE analyses and equation based methods such as those described in section 2.

4. Based on the above, make recommendations for assessing the remaining strength of corroded pipe up to grade X100.

4 BP EXPLORATION TEST PROGRAM

Advantica has recently completed a series of burst tests for BP Exploration to investigate the corrosion defect tolerance of 52-inch grade X100 line pipe. Tests were undertaken using both ring expansion and full-scale vessels. The test report and interpretation is described in [24]. Briefly, the test program comprised 39 ring tests and 4 full-scale vessel tests. Defects were machined on the external surface of the pipe defects to simulate areas of metal loss. Patch, groove and slit type defects were investigated.

The following was concluded from this work:

1. The 52-inch diameter grade X100 material supplied by BP Exploration for the program achieved the minimum material specification requirements of CSA Z245.1-02 [25].

2. The failure pressures obtained from the ring expansion tests were insensitive to defect type.

3. The failure pressures obtained from the vessel tests were sensitive to the defect type. Failure pressures for groove defects were less than those for patch defects.

5 FAILURE PREDICTIONS USING FINITE ELEMENT ANALYSES

The Level 3 finite element (FE) analysis method described in Annex G of BS 7910 [9] was used to predict the failure pressure of grade X65, X80 and X100 pipeline with a single corrosion defect. A description of the defect dimensions and nomenclature is illustrated in Figure 3. In order to validate the results of the FE analyses, a selection of the burst tests from the BP Exploration test program described in section 4 was also modeled. To investigate the sensitivity to failure pressure with increasing material grade two pipe geometries were investigated as follows:

- Pipe diameter, D, 36 inch (914.4mm) and wall thickness, t, 12.7mm [D/t=72]
- Pipe diameter, D, 48 inch (1219mm) and wall thickness, t, 15.9mm [D/t=76.7]

Defects of depths ranging from 20% to 80% and of lengths 4t, 8t, 16t, 32t, 48t, 64t and 80t were considered. Table 4 shows a matrix of the 105 cases that were analyzed. A further series of FE analyses were also undertaken to model selected burst tests on 52-inch diameter grade X100 line pipe conducted by Advantica for BP Exploration [24]. The test cases modeled are summarized in Tables 5 and 6.

5.1 Method

Volumetric metal loss corrosion defects in pipelines are generally present as smooth profiled areas with a reduced ligament of the pipe wall. The failure mechanism of this type of defect is dominated by plastic collapse at the remaining ligament. As with any FE simulation the results obtained are highly dependent upon the assumptions made in the generation of the model, the material properties and boundary conditions.

The failure pressure of internally pressurized ductile steel pipe with either local or general metal loss defects, such as corrosion, can be predicted by numerical analysis using the non-linear FE method and a validated failure criterion. Complex flaw shapes and combined loading conditions can be considered in the analysis. This method is described in BS 7910 Annex G [9] and the PRCI Corrosion Assessment Guidance Document [26]. Briefly, the method, consists of four major steps as follows:

- Create a finite element model of the corroded pipe or vessel, using information on the flaws detected, the measured material properties and the structural constraints and applied loads.
- Perform a non-linear large deformation stress analysis using a validated finite element analysis software package and an appropriate analysis procedure.
- Examine analysis results obtained from the stress analysis.
- Determine the failure or critical pressure value based on the variation of local stress or strain states with reference to a validated criterion or test work.

5.2 Model Generation

For the vessel models, quarter symmetry, three-dimensional (3D) non-linear FE models were created as shown in Figure 4. The models were created using the mesh generating software MSC PATRAN [27] and analyzed using the commercially available finite element code, ABAQUS/Standard [28]. The 3D models were constructed using twenty noded, reduced integration brick elements (ABAQUS type C3D20R). As recommended in Annex G of BS 7910 [9], care was taken to ensure that at least four layers of elements were used through the remaining ligament of each corrosion defect. This was to ensure that the high stress gradients could be predicted with sufficient accuracy in the main areas of interest. The mesh density used for the models was based on prior experience. All groove defects were modeled to be round bottomed with spherical ends, the radius of which is equal to the wall thickness, t, so each defect was modeled with a width equal to 2t.

The ring expansion specimens were modeled using two-dimensional (2D), 4 noded plane strain solid elements (ABAQUS type CPE4) with one plane of symmetry, see Figure 5. Patch defects were modeled with a spherical radius to give a circumferential surface width, W, of approximately 4 times the pipe wall thickness. The groove defects were modeled to be round bottomed with spherical ends, the radius of which is equal to the required defect depth, as shown in Figure 5. The slits were modeled with a rounded bottom of radius equal to half the width.

5.3 Loading and Boundary Conditions

Failure pressures were investigated for internal pressure loading only. For each model the load was applied as a monotonically increasing internal pressure. External loading was not considered.

For the 3D models, symmetry boundary conditions were used to reduce the size of the FE models. Two axes of symmetry were applied to the quarter models, in the x=0 and z=0 planes (see Figure 4). The model was not allowed to rotate, or to expand or contract axially. This simulates a buried pipe in which axial expansion and contraction is restricted by the soil. The model was however allowed to expand and contract radially. Rigid body motion was prevented by restraining nodes in the axial direction at the end of the cylinder furthest away from the area of interest. The cylindrical shell was extended sufficiently far away to ensure the application of boundary conditions did not affect stresses in the area of interest.

In order to represent the pipe sections being capped off, pressure end loads were applied to the unrestrained end of the model.

For the 2D plane strain models, one axis of symmetry was applied in the x=0 plane (see Figure 5). Rigid body motion was prevented restraining one node in the y direction at the bottom center of the ring, furthest away from the area of interest.

5.4 Material Properties

Stress versus strain curves were obtained for grade X65, X80 and X100 line pipe material. Data from round bar tests was used in preference to data from flattened strap tests. For FE analyses, data from round bar tests is considered more reliable as the Bauschinger effect can influence stress versus data from flattened strap tests. Data for each material grade was obtained as follows:

- **Grade X65**

Data for a typical grade X65 line pipe material has been extensively used in previous PRCI projects by Advantica. The data was obtained from a modern 32-inch diameter and ¾ inch (19.05mm) thick API 5L Grade X65 steel as part of the Line Pipe Corrosion Group Sponsored Project [12]. Tensile test data was available for both longitudinal and circumferential directions. There was little variation in the properties in either direction and a mean fit of the tensile test results was used for the FE analyses.

- **Grade X80**

Data was obtained from the public domain and from PRCI member companies. The data was obtained from four 32-inch diameter by ¾ inch (19.05mm) thick and four 48-inch diameter by ⅝ inch (15.9mm) line pipe specimens.

- **Grade X100**

Stress versus strain data for 52-inch diameter grade X100 line pipe was available from the BP Exploration test program, see section 4. Data was also available from a Joint Industry Project (JIP) on X100 that was led by Advantica and from published work, primarily from the 2004 ASME International Pipeline Conference (IPC) proceedings [29].

It is to be noted that grade X100 line pipe is at present only recognized by the Canadian standard, CSA Z245.1-02 [30]. The specified minimum yield strength (SMYS) and tensile strength (SMTS) are quoted as 690 and 760MPa respectively, with a maximum yield to tensile strength ratio of 0.93. Yield strength is quoted at a total strain of 0.5%, designated $R_{t0.5}$.

A summary of the specified minimum and true ultimate tensile strength (UTS) of each material grade is summarized in Table 7.

Figure 6 shows a compilation of stress versus strain curves obtained from the sources described above. When defining plasticity data in FE codes such as ABAQUS/Standard, true stress versus true strain data must be used, where zero plastic strain corresponds to the yield point of the material. The equations for true stress and true strain are valid only to the onset of necking, i.e. the tensile strength of the material, hence the engineering stress versus strain data used was truncated at this value before being converted to true stress-strain data. This data must be monotonically increasing, ABAQUS/Standard then interpolates linearly for values between those given and the stress is assumed to be constant outside the range defined. A rate-independent plasticity model using the von Mises yield criterion and isotropic hardening rule was adopted.

The true stress versus true strain curves used for each material in the FE simulations are summarized in Figure 7.

All the analyses were undertaken using a Young's Modulus of 210000 MPa (30460 ksi) and a Poisson's ratio of 0.3.

For the FE simulations described in this report round bar stress versus strain data was obtained from the public domain as follows: four grade X80 36-inch diameter x 20mm material samples and four grade X80 48-inch diameter x 15.9mm material samples (two transversely and two longitudinally oriented of each size) [31]; two 36-inch x 14.9mm thick transverse grade X100 material samples [31]; one 36-inch diameter x 19mm thick transverse X100 sample [32]; and 36-inch diameter x 15mm thick transverse samples of grade X80 and X100 materials published in the Proceedings of the 2004 ASME International Pipeline Conference (IPC) [29].

5.5 Method of Predicting Failure Pressures

The method of predicting failure pressure of corroded pipelines using FE analysis is described in Annex G of BS 7910 [9].

For each model analyzed the von Mises equivalent stress was monitored at three points through the ligament of each defect as the internal pressure in the pipe was increased. As shown in Figure 8 the stress variation with increasing internal pressure exhibits three distinct stages. The first stage is a linear response progressing to a point when the elastic limit is reached. As the pressure continues to increase a second stage is evident as plasticity spreads through the ligament; the von Mises equivalent stress increases very slowly because of the constraint of the surrounding pipe wall. The third phase is dominated by material hardening and begins when the von Mises equivalent stress in the entire ligament exceeds the material's yield strength. Once this stage is reached, the whole ligament deforms plastically but failure does not occur immediately due to strain hardening.

For the analyses described in this report, the von Mises equivalent stress was monitored at the ligament for each defect. The failure pressure was determined as being equal to when the mean von Mises equivalent stress at the ligament is equal to the true ultimate tensile strength of the material.

5.6 Results

For each model analyzed, principal stresses away from the defects were monitored and compared with hand calculated stresses for plain pipe under internal pressure loading; good agreement was obtained for each analysis undertaken and this provided confidence that the FE models were behaving as expected.

Figure 9 shows a typical von Mises equivalent stress contour plot, for a 48-inch diameter by 15.9mm wall model (D/t = 76.7) with a 0.8t deep axial groove and a defect length of 32t, at an internal pressure of 3.8MPa, just prior to the predicted failure.

Table 4 summarizes the failure predictions for the vessel (3D) model analyzed. Figures 10 to13 show the sensitivity of failure pressures predicted by the Level 3 FE method with material strength increasing from X65 to X100 and with defect depth increasing from 20% to 80% wall thickness.

6 VALIDATION

6.1 BP Exploration Tests versus FE Failure Predictions

As discussed in section 4, validation of the FE analyses was undertaken using the results of the burst test program on 52-inch diameter grade X100 line pipe fro BP

Exploration. The validation of the method was undertaken using grade X100 material because the high yield to tensile (Y/T) ratio. The validation was undertaken using the results from four vessel and ten ring expansion tests, see Tables 6 and 7.

A comparison of predicted and actual failure pressures is shown in Figure 17 (see Table 4 for values). The results show that the FE method is able to predict failure pressures of corroded grade X100 line pipe to within ±10% of the actual failure pressure. This is consistent with the level of scatter observed for lower strength grades and can be explained by the fact that the FE method is based on an idealized geometry. In reality, there may be some ovality in the test pipe and there may be some local variation in the wall thickness. These factors can explain the differences observed.

6.2 BP Exploration Tests versus Equation Based Methods

Failure pressures obtained form the BP Exploration burst test program were also compared with the predictions from equation based methods (ASME B31G, RSTRENG, LPC-1 and Shannon-Battelle) discussed in section 2. It is noted that for pipelines constructed and operated in the United States, the integrity is managed in accordance with Federal Regulations CFR 192 [33] and 195 [34]. These regulations stipulate use of either ASME B31G or RSTRENG to assess the remaining strength of corroded pipe subject to the limitations prescribed in the procedures.

The comparison of failure pressures calculated by each assessment method is shown in Table 8. The following is concluded:

1. **ASME B31G** – Predicted failure pressures are conservative for long defects and non-conservative for short defects by approximately 10%.

2. **RSTRENG** – Predicted failure pressures tend to be non-conservative for long defects and marginally (to within 2%) conservative for short defects.

3. **LPC-1** – Predicted failure pressures tend to be non-conservative (to within 5%) for long defects but conservative for short defects (to within 5%).

4. **Battelle-Shannon** – Predicted failure pressures are all conservative (in the range 6% to 33%).

For each assessment method, the definition of flow stress specific to the method was used. Flow stress is a concept intended to allow for the increase in strength after yielding. A number of equations have been put forward for calculating flow stress; a review of the methods is described by Denys et al [35].

The following flow stress definitions are used:

ASME B31G	1.1⑨$_{SMYS}$
RSTRENG	⑨$_{SMYS}$ +10ksi
LPC-1	⑨$_{SMTS}$

As already discussed in section 2 these methods have been validated using line pipe grade up to X65. For higher strength steels, the yield to tensile (Y/T) ratio increases and the definition of the flow stress used by ASME B31G and RSTRENG approaches the yield strength; this is clearly unrealistic. For higher strength steels, an alternative is to calculate flow stress based on the average of the yield and tensile strength, as recommended in BS 7910 [9], where the flow stress is given by Equation (19).

$$\sigma_{flow} = \frac{\sigma_{SMYS} + \sigma_{SMTS}}{2} \tag{19}$$

If the predictions were revisited using the BS 7910 flow stress definition, the predicted failure pressures can be scaled proportionally according to equation (20):

$$\text{Scaling factor} = 1 - \left(\frac{\sigma_{flow(BS7910)}}{\sigma_{flow}} \right) \tag{20}$$

The revised flow stress definition would result in increased margins of conservatism in the predicted failure pressures. A comparison of test results and failure predictions using common equation based methods (ASME B31G, RSTRENG, LPC-1) is shown in Figures 18 to 20. Predictions are presented using the flow stress definitions for each assessment method and also with the BS 7910 flow stress definition. The results show that both the ASME B31G and RSTRENG methods can give non-conservative failure predictions, even when the flow stress definition has been modified. Non-conservative predictions are obtained particularly for deep defects. Using the flow stress definition of ⑨$_{SMTS}$ for the LPC-1 method can give non-conservative failure predictions. If the flow stress definition is modified to that given in BS 7910, then the failure predictions become conservative. For completeness a comparison using the Battelle-Shannon method is shown in Figure 21. The Battelle-Shannon Method consistently gives conservative failure predictions.

7 DISCUSSION

Compared with the test results, the ASME B31G and RSTRENG method can give non-conservative failure predictions for assessing the remaining strength of corroded, higher strength pipelines. This conclusion has been based on a comparison using full-scale tests on grade X100 line pipe. It is expected that a similar conclusion would be obtained for grade X80 line pipe also. It is to be noted that both ASME B31G and RSTRENG can give non-conservative failure predictions for lower grade line pipe when assessing deep defects (i.e. approaching 80% of the wall thickness), see for example [36].

The LPC-1 method gives the most accurate prediction of failure pressure of corroded higher strength line pipe. However the method can give non-conservative predictions. Modifying the flow stress to that recommended in BS 7910 gives in conservative failure predictions.

Based on the above discussion, it is recommended that the LPC-1 method is used to assess the remaining strength of corroded grade X80 and X100 line pipe, with the flow stress modified to be equal to the average of the specified minimum yield and ultimate tensile strength.

8 CONCLUSIONS

1 The ASME B31G and RSTRENG methods can give non-conservative failure predictions when assessing the remaining strength of higher strength (grade X80 and X100) corroded pipelines.

2 The LPC-1 method is the most accurate method for assessing the remaining strength of corroded higher strength (up to X100) pipelines. However, LPC-1 can give non-conservative failure predictions.

3 The non-linear FE method used to predict the failure pressure is valid for higher strength steels up to grade X100.

4 The LPC-1 method, with the flow stress modified to equal the average of the specified minimum yield and ultimate tensile strength, predicts conservative failure pressures for corroded pipelines of grades up to X100.

9 RECOMMENDATIONS

1 The remaining strength of corroded pipe of grade higher than X65 should be assessed using the LPC-1 method but with the flow stress modified to be equal to the average of the specified minimum yield and ultimate tensile strength.

2 Further testing and assessment is undertaken to validate the method by investigating the sensitivity to pipe (*D/t*) ratio and defect shape.

3 The assessment method should be extended to consider defect interaction and external secondary loading.

10 REFERENCES

[1] Anon: ASME B31G-1991 (revision of ANSI/ASME B31G-1984): Manual for determining the remaining strength of corroded pipelines - a supplement to ASME B31 code for pressure piping, The American Society of Mechanical Engineers, New York, 1991

[2] Kiefner JF and Veith PH: 'A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe', Final Report on PR-3-805 to the Pipeline Research Committee of the American Gas Association, Battelle, Ohio, 1989

[3] Vieth PH and Kiefner JF: 'RSTRENG2 User's Manual, Final report on PR-218-9205 to Corrosion Supervisory Committee, Pipeline Research Committee, American Gas Association, Kiefner & Associates, Inc., Ohio, 1993

[4] Fu, B. and Batte, A.D. 'Advanced Methods for the Assessment of Corrosion in Linepipe. Summary Report OTO 97065, UK Health and Safety Executive

[5] Anon: ASME B31G-1991 (revision of ANSI/ASME B31G-1984): Manual for determining the remaining strength of corroded pipelines - a supplement to ASME B31 code for pressure piping, The American Society of Mechanical Engineers, New York, 1991

[6] Kiefner JF and Veith PH: 'A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe', Final Report on PR-3-805 to the Pipeline Research Committee of the American Gas Association, Battelle, Ohio, 1989

[7] Vieth PH and Kiefner JF: 'RSTRENG2 User's Manual, Final report on PR-218-9205 to Corrosion Supervisory Committee, Pipeline Research Committee, American Gas Association, Kiefner & Associates, Inc., Ohio, 1993

[8] Fu, B. and Batte, A.D. 'Advanced Methods for the Assessment of Corrosion in Linepipe. Summary Report OTO 97065, UK Health and Safety Executive

[9] Anon: 'Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures', BS 7910:2005, BSI, 27 July 2005

[10] Anon: 'Corroded Pipelines', Recommended Practice DNV-RP-F101, Det Norske Veritas, October 2004

[11] Anon: 'Fitness-For-Service', API Recommended Practice 579, American Petroleum Institute, First Edition, January 2000

[12] Fu B and Vu DQ: 'Failure of Corroded Line Pipe (1) - Experimental Testing', Technical report GRTC R.1803, BG Technology, Loughborough, 1997. (Advantica Confidential)

[13] Anon: 'ASME Boiler and Pressure Vessel Code, Rules for Construction of Pressure Vessels', American Society of Mechanical Engineers, 2004

[14] Anon: 'Power Piping', ASME B31.1, American Society of Mechanical Engineers, 2004

[15] Anon: 'Process Piping', ASME B31.3, American Society of Mechanical Engineers, 2004

[16] Anon: 'Welded Steel Tanks for Oil Storage', API 650, American petroleum Institute, 2003

[17] Anon: ' Design and Construction of Large, Welded, Low-Pressure Storage Tanks, API 620, Tenth Edition (with Addenda June 2004 Addenda)', American Petroleum Institute, 2002

[18] Vieth PH and Kiefner JF: 'Database of Corroded Pipe Tests, Final report on PR-218-9206 to Line Pipe Research Supervisory Committee, Pipeline Research Committee, American Gas Association, Kiefner & Associates, Inc., Ohio, 1994

[19] Shannon, RWE 'The Failure Behaviour of Line Pipe Defects', International Journal of Pressure Vessels and Piping, Vol.2, pp.243-255, 1974

[20] Fu B, Stephens D, Ritchie D and Jones CL: 'Methods for Assessing Corroded Pipeline – Review, Validation and Recommendations', Prepared for Pipeline Research Council International, Inc., Catalog. No. L51878, Advantica Technologies, Inc., October 2000

[21] Kiefner JF, Vieth PH and Roytman I: 'Continued Validation of RSTRENG', Final report on PR-218-9304 to Line Pipe Research Supervisory Committee, Pipeline Research Committee of PRC International, Kiefner & Associates, Inc., Ohio, 1996

[22] Hopkins P and Jones DG: 'A Study of the Behaviour of Long and Complex-Shaped Corrosion in Transmission Pipelines', Proceedings of the 11th International Conference on Offshore Mechanics and Arctic Engineering (OMAE'91), Vol.5 (Pipeline Technology). New York, American Society of Mechanical Engineers, pp.211-218. 1991

[23] Craig G and Sisterson G: 'Simulated Corrosion Full-Scale tests', British Gas Technical Report ERS R.4648, Engineering Research Station, Newcastle-upon-Tyne, 1991. (Advantica Confidential)

[24] Wood, A., Morgan, G. and Swankie, T. 'Ring Tension and Full Scale Burst Testing of Grade X100 Linepipe Material' Advantica report R7702 Issue 1, November 2005

[25] Anon, 'Steel pipe', CSA Z245.1-02, Canadian Standards Association, Mississauga, Ontario, Canada, 2002

[26] Fu. B, Jones, C.L. and Chauhan, V. 'Guidance for Assessing the Remaining Strength of Corroded Pipeline', Advantica, Inc Report Prepared for the Materials Technical Committee of Pipeline Research Council International Inc., August 2002 Contract PR-273-9803, Catalogue No. L51958

[27] MSC.PATRAN version 2001 r3, MSC.Software Corporation

[28] ABAQUS/Standard, version 6.4.1, ABAQUS, Inc.

[29] Sadasue, T. et al, 'Ductile Cracking Evaluation of X80/X100 High Strength Pipelines', IPC04-0249, Proceedings of the 2004 ASME, International Pipeline Conference, Calgary, Alberta, Canada. October 4-8, 2004

[30] Anon. 'Steel Line Pipe, Including Update 1', CSA Z245.1-02, Canadian Standards Association, Mississauga, Ontario, Canada, 2002.

[31] Martin M., Swankie, T., Andrews, R.M., 'Methods of Assessing and Specifying the Strain Hardening Behaviour of High Strength Steels', Project reference: GTI-PR-00503, PR-273-0356, Advantica, Inc., (in progress)

[32] Andrews R.M, Edwards A.M, Espiner R.J., Yates J.R., Howard I.C., Hashemi S.H., 'Damage mechanics studies on high strength linepipe'. 15th Joint Technical Meeting on Linepipe Research, Orlando, May 16-20 2005. Arlington, Virginia: Pipeline Research Council International; 2005. Paper 10. (Confidential to PRCI, EPRG and APIA)

[33] Anon. '49 CFR Part 192 Pipeline Safety: 'Transportation of Natural Gas Other Gas by Pipeline: Minimum Federal Safety Standards, US Department of Transportation, Research and Special Programs Administration, October 2005

[34] Anon. '49 CFR Part 195 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline); Final Rule, US Department of Transportation, Research and Special Programs Administration, October 2005

[35] Denys, RM, Lefevre, AA, De Baets, P and J Degrieck, 'Effects of Stable Ductile Crack Growth on Plastic Collapse of Defect Assessments', Pipeline Technology, Volume 1, Edited by RM Denys, Elsevier Science B.V., 2000

[36] Fu, B., Stephens, D., Ritchie, D. and Jones, C.L. 'Methods for Assessing Corroded Pipeline – Review, Validation and Recommendations', PRCI Report, Catalog No. L51878, Advantica Technologies Ltd., October 2000

11 TABLES

Pipe Diameter, d (mm)	406.4	to	762.0
Wall Thickness, t (mm)	7.87	to	9.65
D/t ratio	51.3	to	81.1
Material Grade (API 5L)	A25	to	X52
d/t ratio	0.31	to	1.0
Defect Length (2c), mm	0.7	to	7.8
Defect Width, w (mm)	Not Available		
Burst Pressure, P_f (bar)	56.5	to	147.5

Table 1 Range of Experimental Parameters Used to Validate the ASME B31G Method

Pipe Diameter, d (mm)	273.0	to	1219.2
Wall Thickness, t (mm)	5.00	to	12.7
D/t ratio	40.6	to	130.3
Material Grade (API 5L)	A	to	X65
d/t ratio	0.28	to	1.0
Defect Length (2c), mm	19.4	to	3048
Defect Width, w (mm)	0.15	to	762
Burst Pressure, P_f (bar)	41.3	to	209

Table 2 Range of Experimental Parameters Used to Validate the RSTRENG Method

Pipe Diameter, d (mm)	219.1	to	914.4
Wall Thickness, t (mm)	3.4	to	25.4
(D/t) ratio	8.6[2]	to	149.4
Material Grade (API 5L)	X42	to	X65
d/t ratio	0.2	to	0.97
Defect Length (2c), mm	40.8	to	2000
Defect Width, w (mm)	0.15	to	334
Burst Pressure, P_f (bar)	46	to	1241

Table 3 Range of Experimental Parameters Used to Validate the BS 7910 and DNV RP-F101 Methods

[2] 7 tests were undertaken on Grade X52 pipe with wall thicknesses ranging from 24.5mm to 25.4mm. All vessels contained external groove defects with a (d/t) ratio range 0.2 to 0.94. Deeper defects resulted in failure of the vessel as a leak. Failure of the vessel by rupture was obtained for defect (d/t) ratios in the range 0.5 to 0.72. Failure pressures ranged from 685 bar to 1241 bar.

Model Dimensions			Material Grade	Failure Pressure Prediction (MPa)								
D (in/mm)	t (in/mm)	D/t		Defect Type	Depth (d)	Length (L)						
						4t	8t	16t	32t	48t	64t	80t
36 / 914.4	0.5 / 12.7	72	X65	Axial groove	0.2t	17.7	17.1	16.6	16.3	16.2	16.2	16.1
					0.5t	16.1	14.0	12.9	10.9	10.4	10.2	10.2
					0.8t	14.2	11.5	7.2	4.6	4.1	4.0	4.0
36 / 914.4	0.5 / 12.7	72	X80	Axial groove	0.2t	19.4	18.8	17.9	17.1	16.9	16.7	16.7
					0.5t	18.3	15.3	12.4	10.5	10.4	10.3	10.3
					0.8t	16.1	11.1	6.6	4.5	4.0	4.0	4.0
36 / 914.4	0.5 / 12.7	72	X100	Axial groove	0.2t	24.6	24.3	23.2	22.2	21.3	21.3	21.3
					0.5t	23.5	19.5	15.3	13.4	13.3	13.3	13.3
					0.8t	20.2	13.5	8.1	5.4	5.1	5.2	5.2
48 / 1219	0.626 / 15.9	76.7	X65	Axial groove	0.2t	16.6	16.1	15.6	15.3	15.2	15.1	15.1
					0.5t	15.1	13.9	12.1	10.3	9.7	9.6	9.6
					0.8t	13.4	10.9	6.9	4.3	3.9	3.8	3.8
48 / 1219	0.626 / 15.9	76.7	X80	Axial groove	0.2t	18.1	17.7	16.8	16.2	15.8	15.8	15.8
					0.5t	17.1	14.8	11.7	10.1	9.6	9.8	9.8
					0.8t	15.0	10.6	6.4	4.2	3.7	3.8	3.8

Table 4 Matrix of FE Analyses for Axial Groove Defects

Ring ID	Defect Type	Geometry		Defect Dimensions		Test Failure Pressure	
		D mm	t mm	W mm	d/t	MPa	psi
HKL-R06	Patch	1318	22.87	91.2	0.294	21.3	3088.5
HKL-R12	Patch	1319	22.85	91.8	0.809	6.17	894.7
HKB-R01	Patch	1318	20.62	83.5	0.102	23.3	3371.3
HKB-R03	Patch	1318	20.62	82.5	0.503	13.2	1912.6
HKL-R15	Groove	1318	22.77	9.9	0.204	25.0	3628.0
HKL-R19	Groove	1318	22.80	36.8	0.810	6.3	917.9
HKB-R06	Groove	1318	20.67	20.9	0.504	14.3	2075.0
HKL-R22	Slit	1319	22.84	0.15	0.102	28.2	4090.5
HKL-R27	Slit	1319	22.85	0.15	0.804	5.6	812.0
HKB-R10	Slit	1318	20.79	0.15	0.493	14.2	2057.6

Table 5 Ring Expansion Results from BP Exploration Test Program

Vessel ID	Defect Type	Geometry		Defect Dimensions		Test Failure Pressure	
		D mm	t mm	W mm	d/t	MPa	psi
HKL V01	Patch	1321	22.80	608	0.496	18.1	2630.3
HKK V01	Patch	1321	22.80	1108	0.500	15.4	2231.6
HKL V02	Groove	1321	22.80	514	0.503	17.9	2601.3
HKK V02	Groove	1321	22.85	1012	0.500	15.0	2179.3

Table 6 Vessel Test Results from BP Exploration Test Program

Material	SMYS (MPa)	SMTS (MPa)	Flow Stress (MPa)				
			ASME B31G	RSTRENG	LPC-1	Shannon-Battelle	BS 7910
X65	448	530	493	517	530	515	489
X80	551	620	606	620	620	634	586
X100	690	760	759	759	760	794	725

Table 7 Material Properties for Grade X65, X80 and X100 Line Pipe

Test Type and ID	Defect Type	Geometry D (mm)	Geometry t (mm)	Defect Dimensions w (mm)	Defect Dimensions d/t (%)	Length (mm)	Test Failure Pressure (MPa)	Failure Pressure Prediction (MPa) FE	ASME B31G	RSTRENG	LPC-1	Battelle Shannon
HKL-R06	Patch	1318	22.87	91.2	29.4	24000	21.3	23.16	17.76 18.60	18.88 19.76	18.15 19.02	17.82 17.82
HKL-R12	Patch	1319	22.85	91.8	80.9	24000	6.17	6.3	5.02 5.26	8.05 8.42	4.93 5.17	5.07 5.07
HKB-R01	Patch	1318	20.62	83.5	10.2	24000	23.25	26.33	22.57 23.63	22.92 24.00	22.99 24.10	22.59 22.59
HKB-R03	Patch	1318	20.62	82.5	50.3	24000	13.19	13.88	11.27 11.80	12.99 13.60	11.53 12.08	11.33 11.33
HKL-R15	Groove	1318	22.77	9.9	20.4	24000	25.02	26.33	19.94 20.88	20.71 21.68	20.35 21.33	19.98 19.98
HKL-R19	Groove	1318	22.8	36.8	81	24000	6.33	6.44	5.02 5.25	8.04 8.41	4.90 5.14	5.06 5.06
HKB-R06	Groove	1318	20.67	20.9	50.4	24000	14.31	14.55	11.28 11.81	13.01 13.62	11.53 12.09	11.33 11.33
HKL-R22	Slit	1319	22.84	0.15	10.2	24000	28.21	29.2	22.55 23.60	22.93 24.01	22.98 24.08	22.57 22.57
HKL-R27	Slit	1319	22.85	0.15	80.4	24000	5.60	6.49	5.02 5.26	8.05 8.42	5.06 5.31	5.07 5.07
HKB-R10	Slit	1318	20.79	0.15	49.3	24000	14.19	15.84	11.60 12.14	13.30 13.92	11.86 12.43	11.65 11.65
HKL V01	Patch	1321	22.8	608	49.6	608	18.1	17.62	18.62 19.50	16.98 17.77	16.59 17.39	15.43 15.43

HKK V01	Patch	1321	22.8	1108	50	1108	15.4	14.69	12.51 13.10	15.86 16.61	14.73 15.44	14.00 14.00
HKL V02	Groove	1321	22.8	514	50.3	514	17.9	13.78	18.87 19.75	17.28 18.09	17.12 17.95	15.81 15.81
HKK V02	Groove	1321	22.85	1012	50	1012	15.0	13.8	12.54 13.13	16.01 16.76	14.97 15.69	14.18 14.18

Table 8 Comparison of Actual and Predicted Failure Pressures Based on the BS 7910 Definition of Flow Stress

Note: Failure predictions in black are based on the flow stress modified to equal the average of the yield and ultimate tensile strength. Failure predictions in red are based on the flow stress stipulated for each assessment procedure.

12 FIGURES

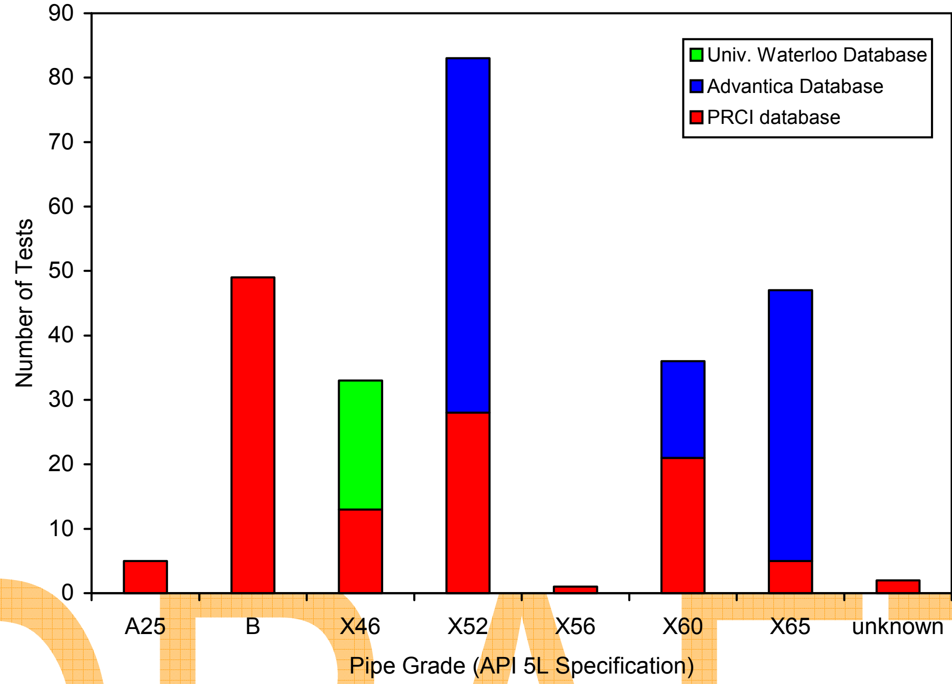


Figure 1 PRCI Review – Pipe Grade Distribution from Corrosion Defect Test Database

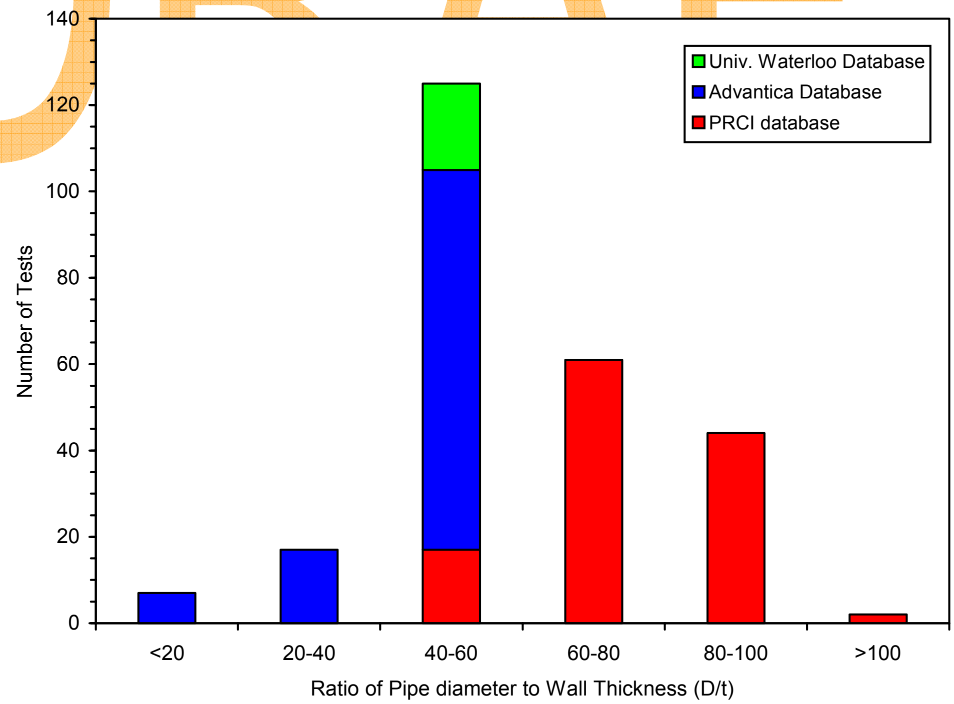


Figure 2 PRCI Review – Pipe (*D/t*) Ratios from Corrosion Defect Test Database

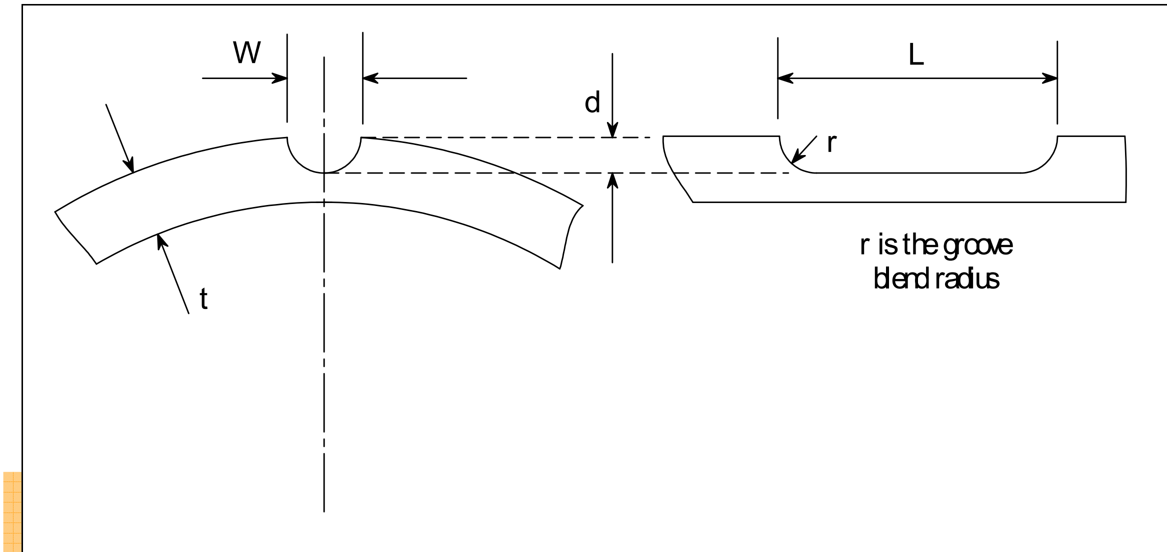


Figure 3 Groove Defect Dimensions

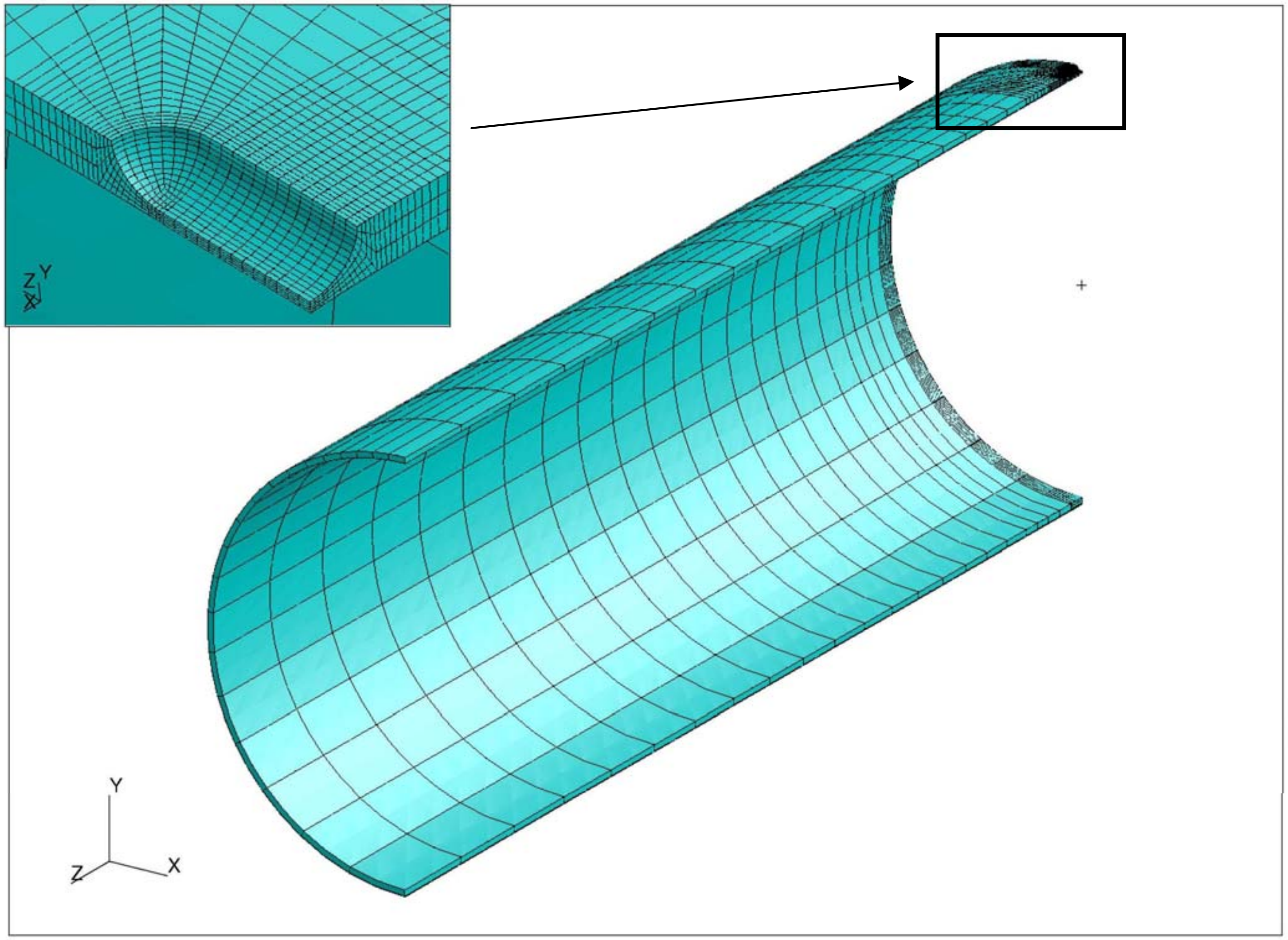


Figure 4 Typical 3D FE Model of an Axial Groove Defect in a Pipeline

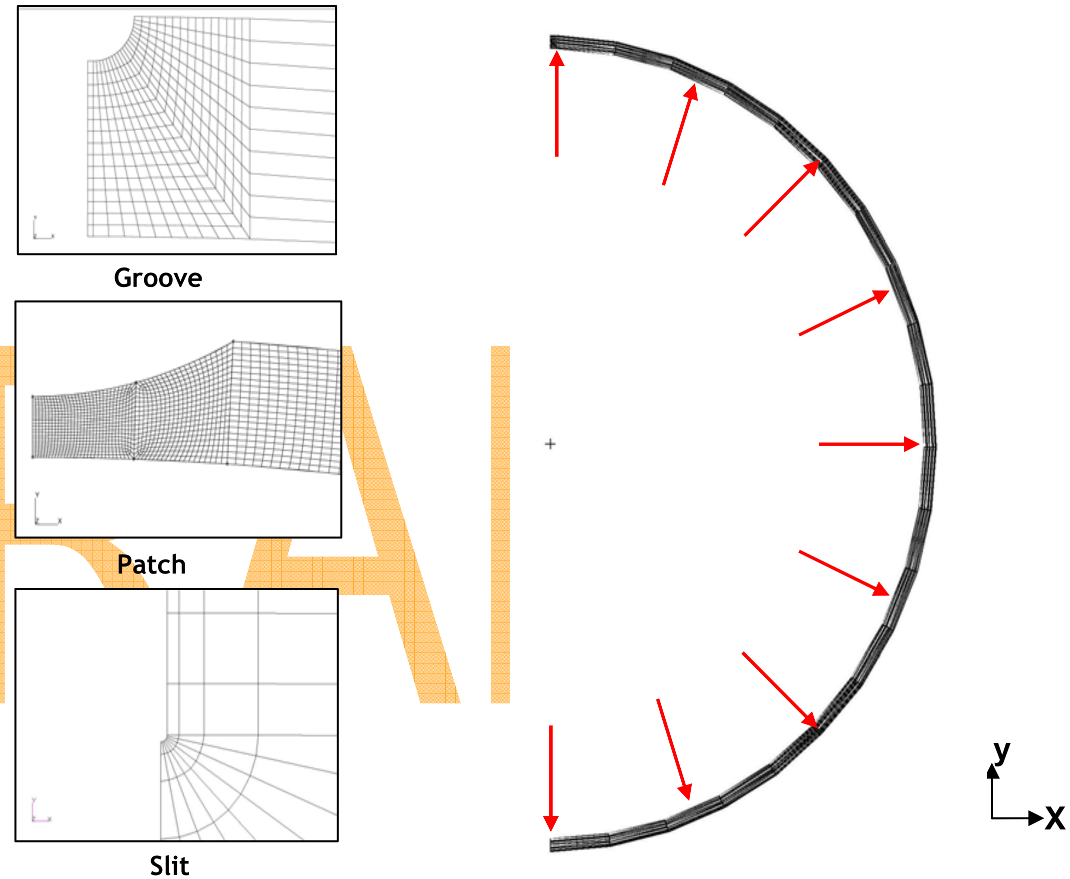


Figure 5 2D Plane Strain FE Models for Ring Expansion

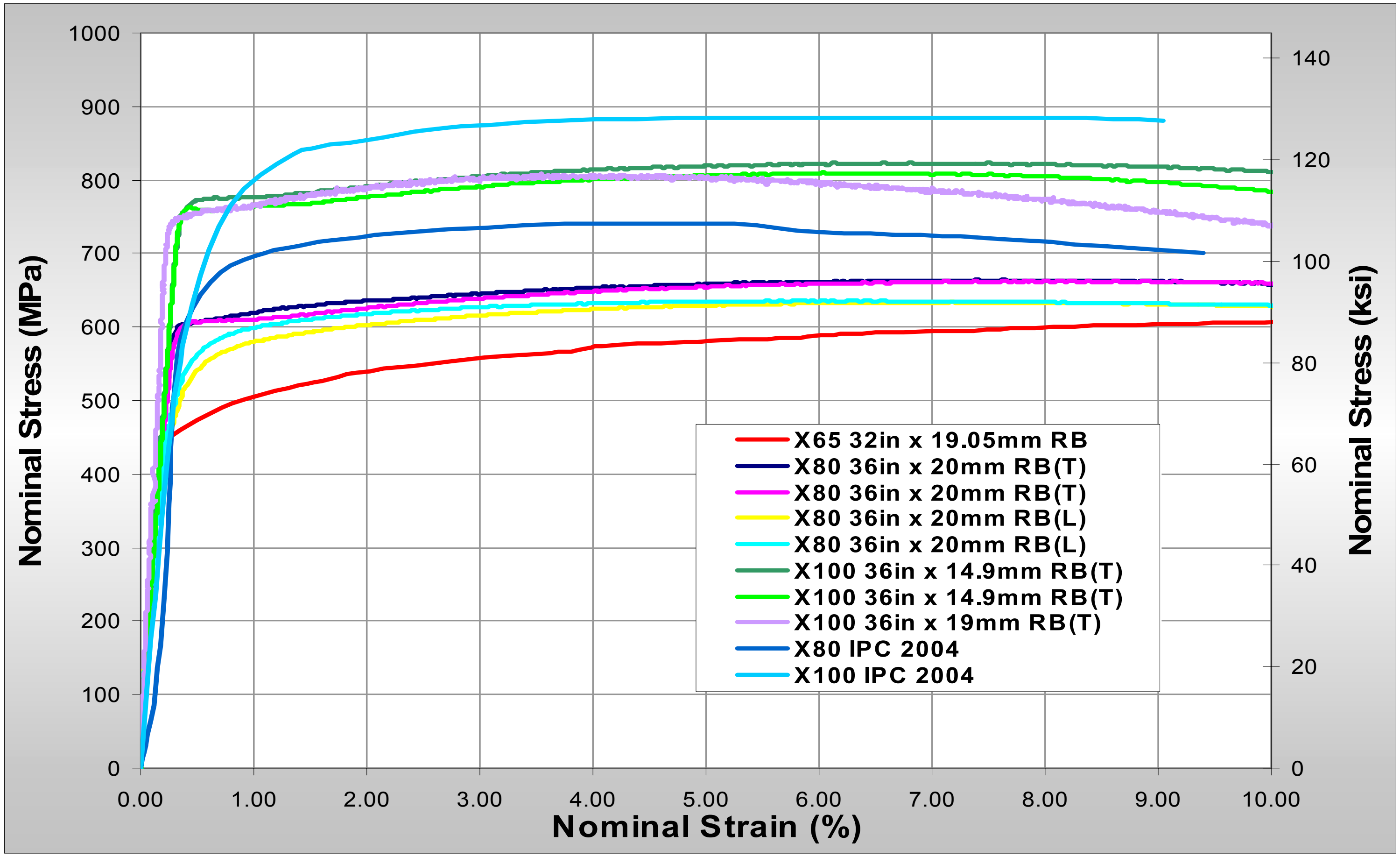


Figure 6 Stress Versus Strain Curves for Grade X65, X80 and X100 Line Pipe

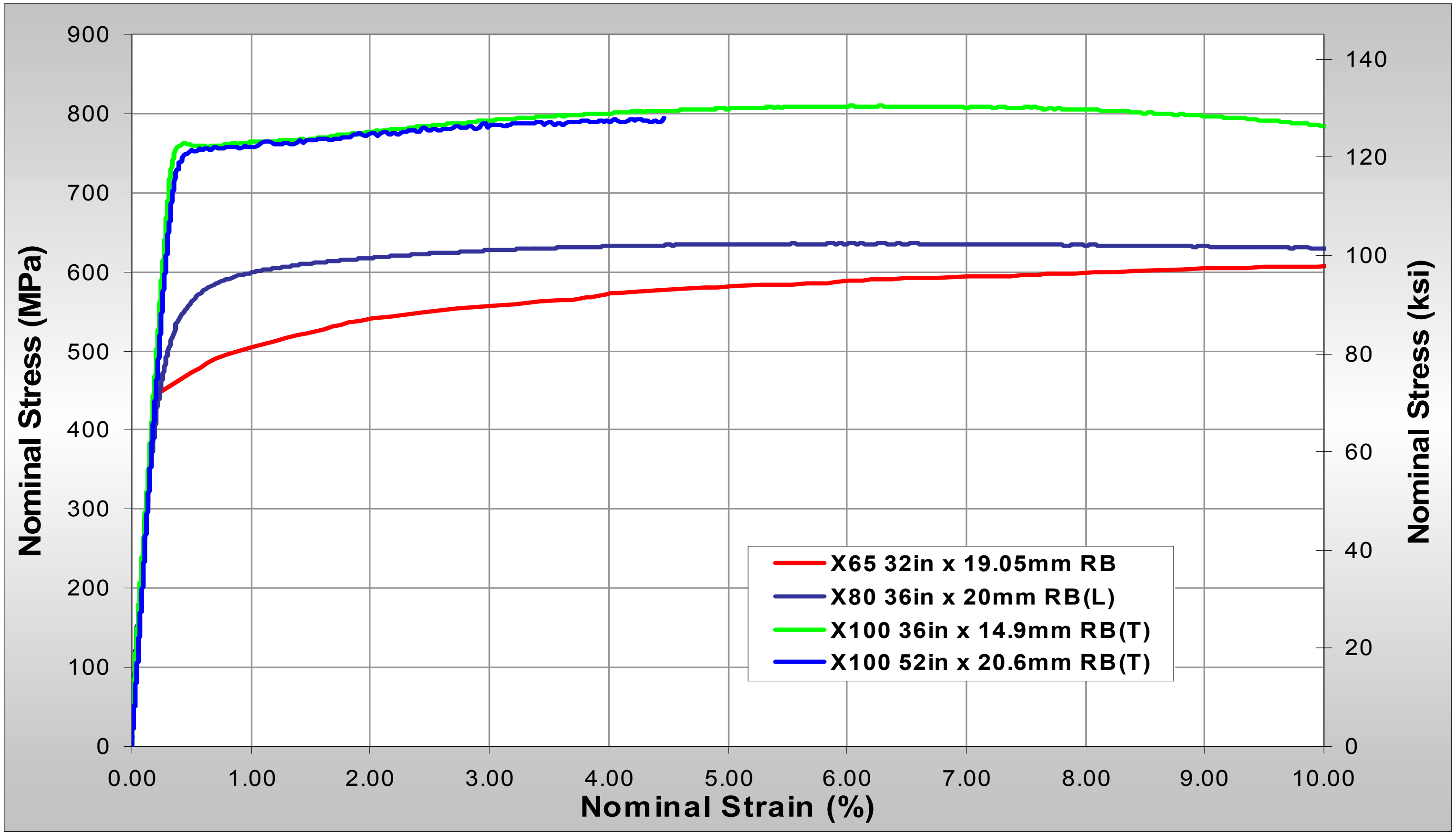
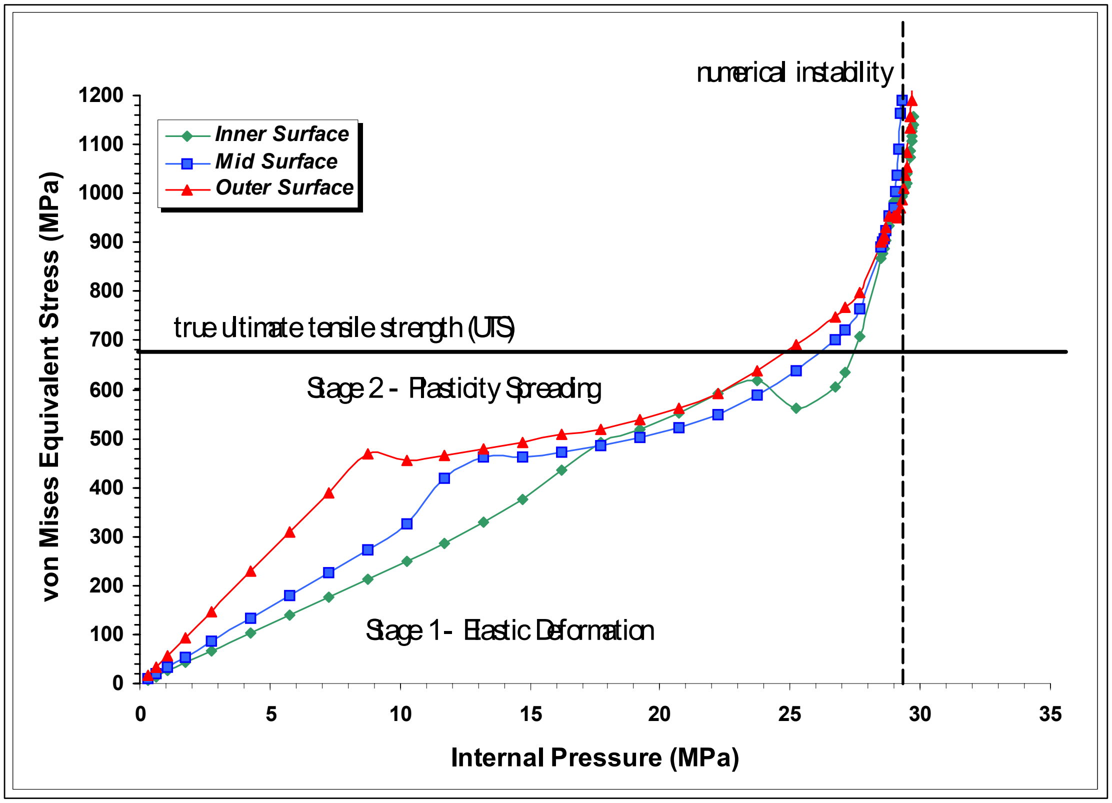


Figure 7 True Stress Versus True Strain Curves for Grade X65, X80 and X100 Line Pipe Used in the FE Simulations



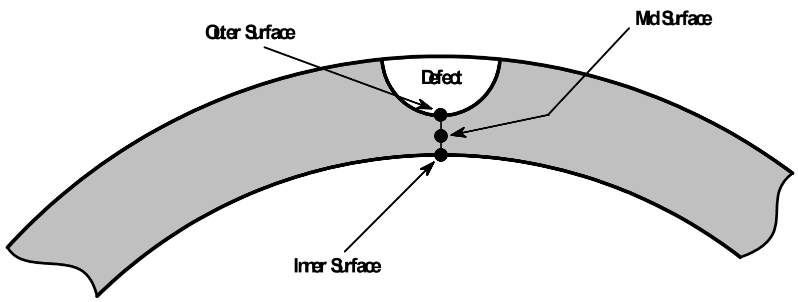


Figure 8 von Mises Equivalent Stress Variation Thru Ligament with Increasing Internal Pressure

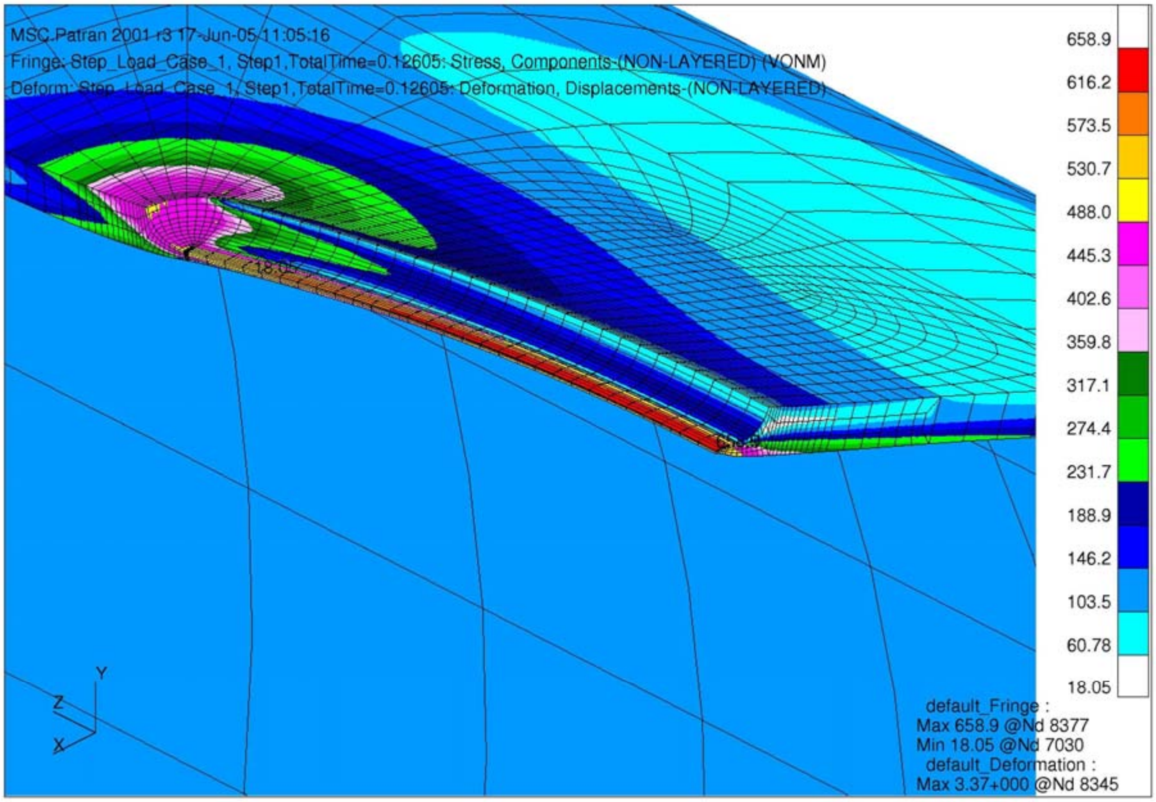


Figure 9 Typical von Mises Equivalent Stress Contour Plot Pipe D/t=76.7, L=32t, d/t=0.8, Pressure=3.8MPa

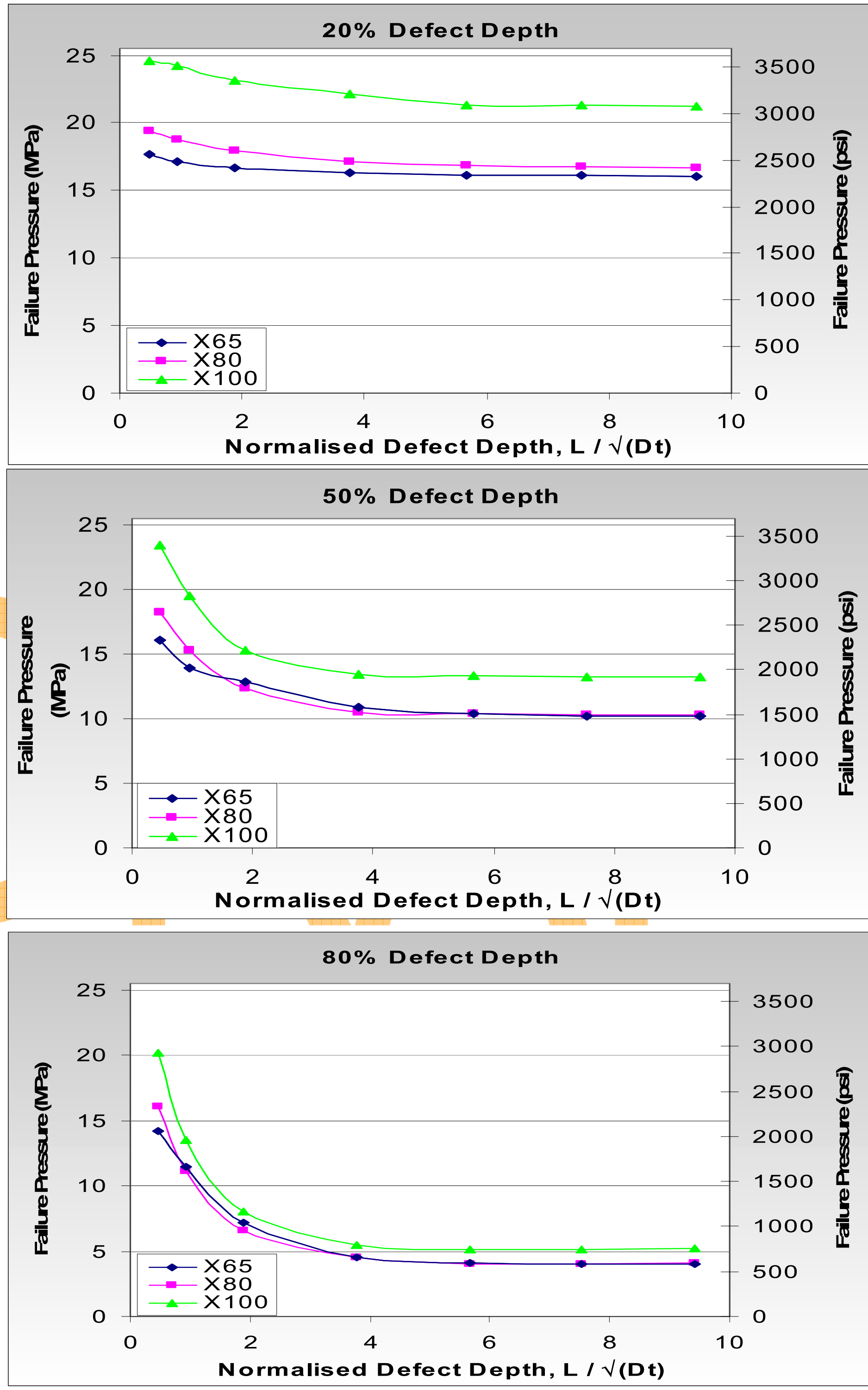


Figure 10 36-inch diameter, D/t=72 Models – Sensitivity of Level 3 Failure Predictions with Increasing Material Strength

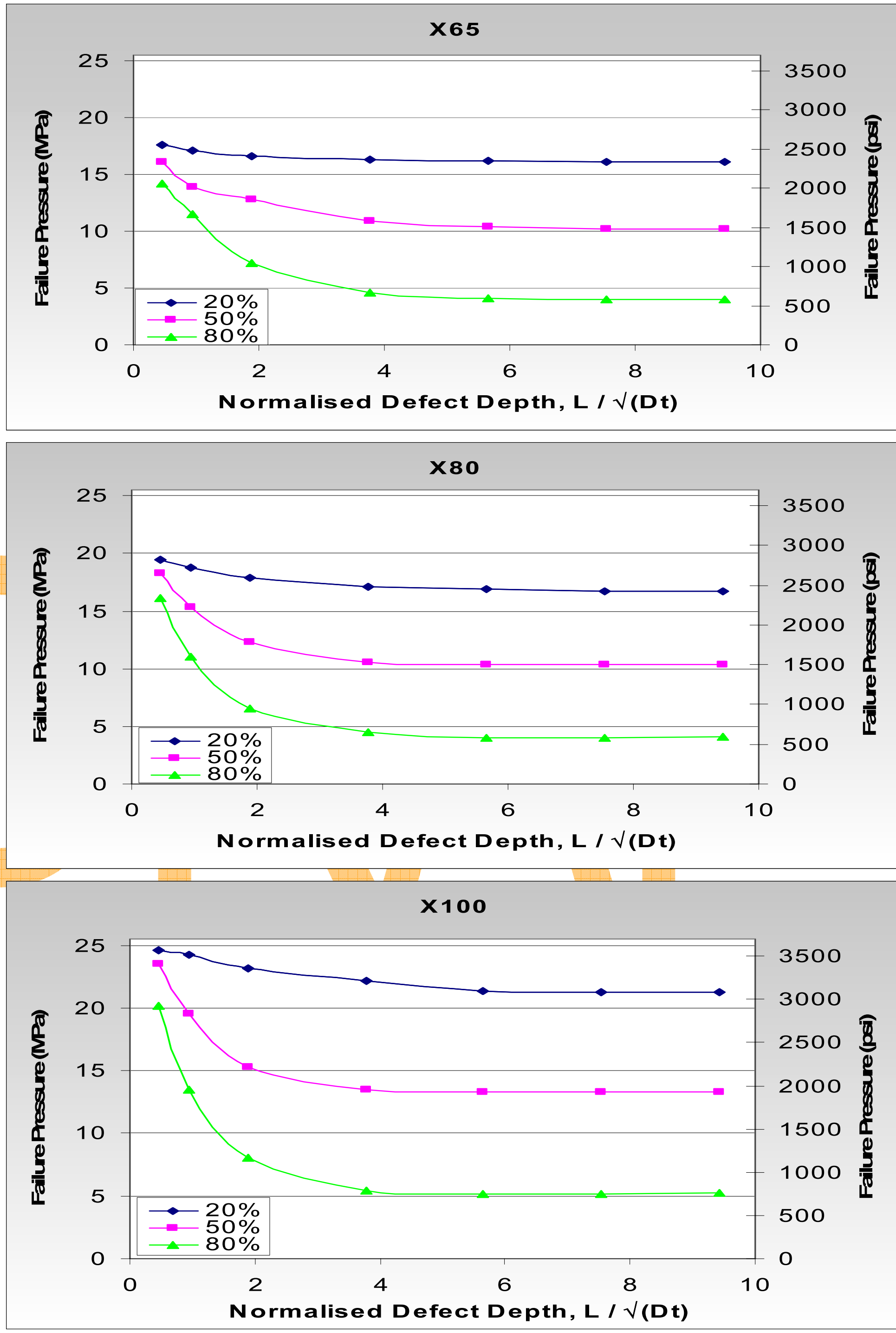


Figure 11 36-inch diameter, D/t=72 Models – Sensitivity of Level 3 Failure Predictions with Increasing Defect Depth

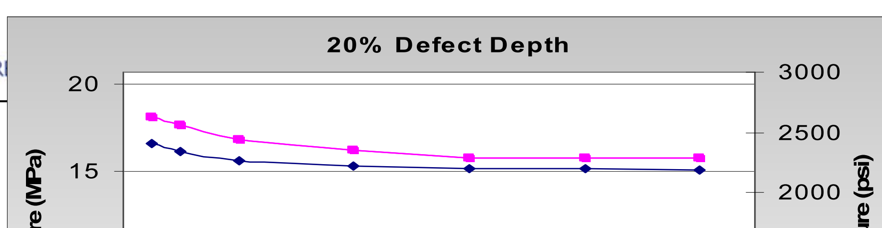


Figure 12 48-inch diameter, D/t=76.7 Models – Sensitivity of Level 3 Failure Predictions with Increasing Material Strength

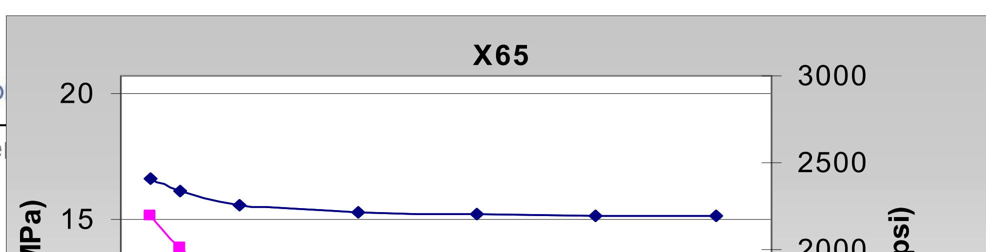


Figure 13 48-inch diameter, D/t=76.7 Models – Sensitivity of Level 3 Failure Predictions with Increasing Defect Depth

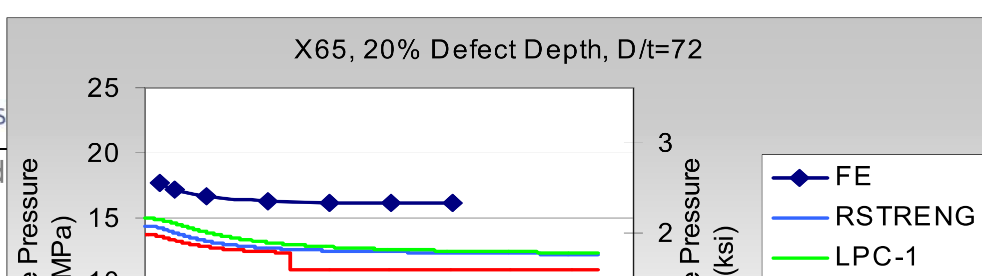


Figure 14 36-inch diameter, D/t=72 Grade X65 Model – Comparison of FE Failure Predictions with Equation Based Methods

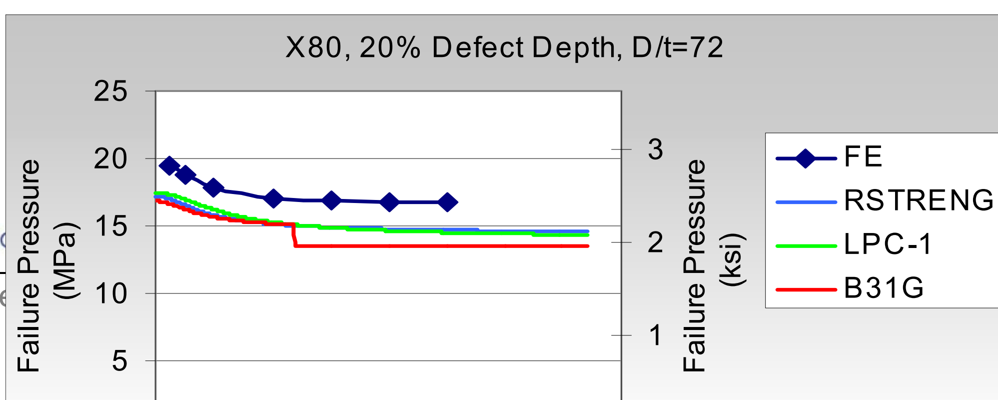


Figure 15 36-inch diameter, D/t=72 Grade X80 Model – Comparison of FE Failure Predictions with Equation Based Methods

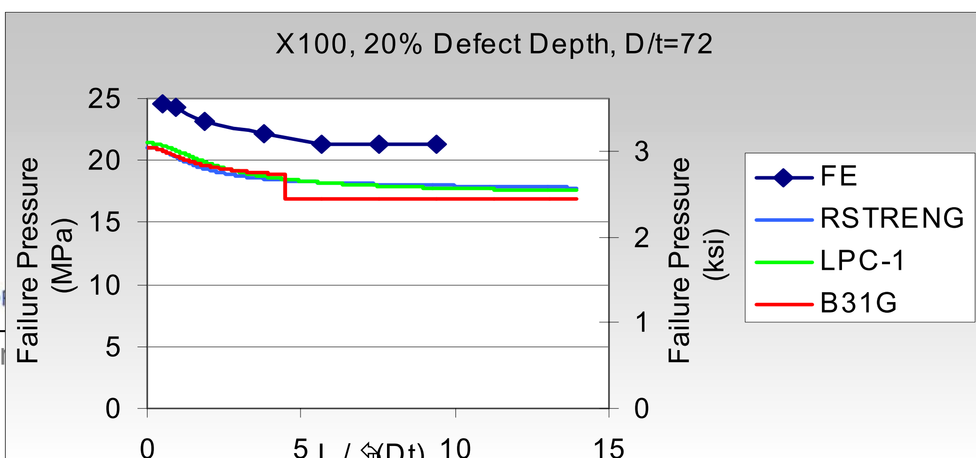


Figure 16 36-inch diameter, D/t=72 Grade X80 Model – Comparison of FE Failure Predictions with Equation Based Methods

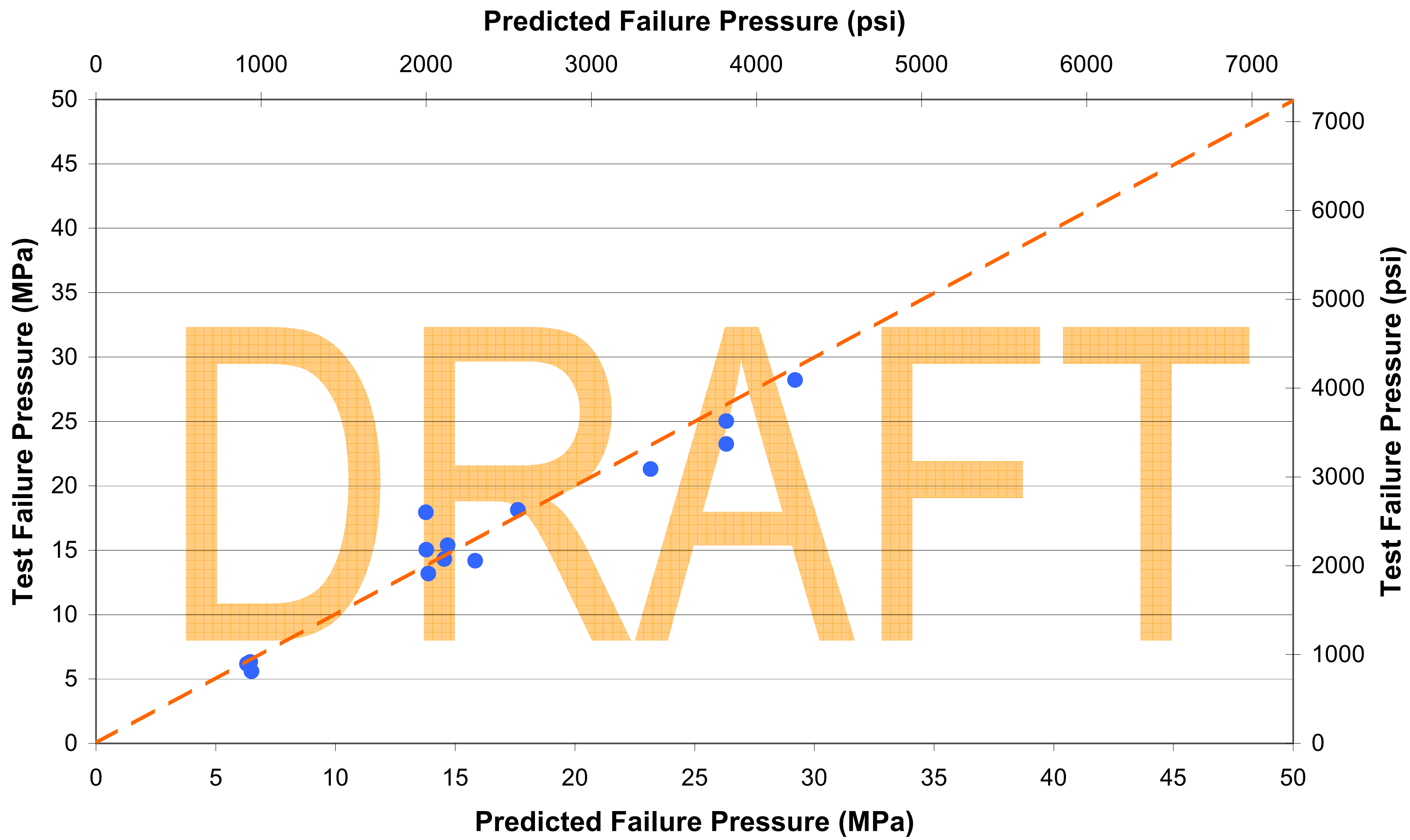


Figure 17 52-inch Diameter Grade X100 Line Pipe. Test versus FE Predicted Failure Pressures

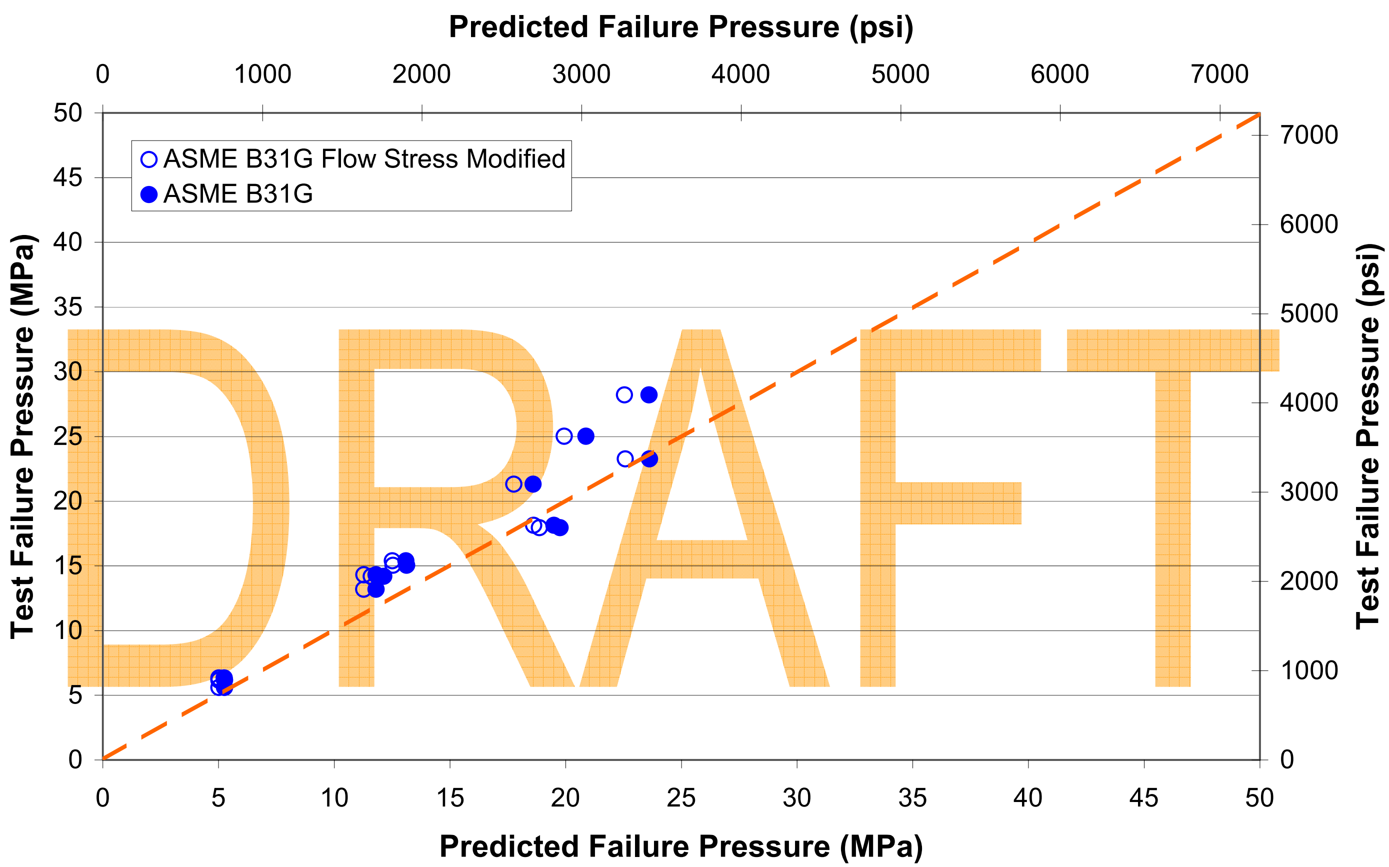


Figure 18 52-inch Diameter Grade X100 Line Pipe. Test versus ASME B31G Failure Pressures

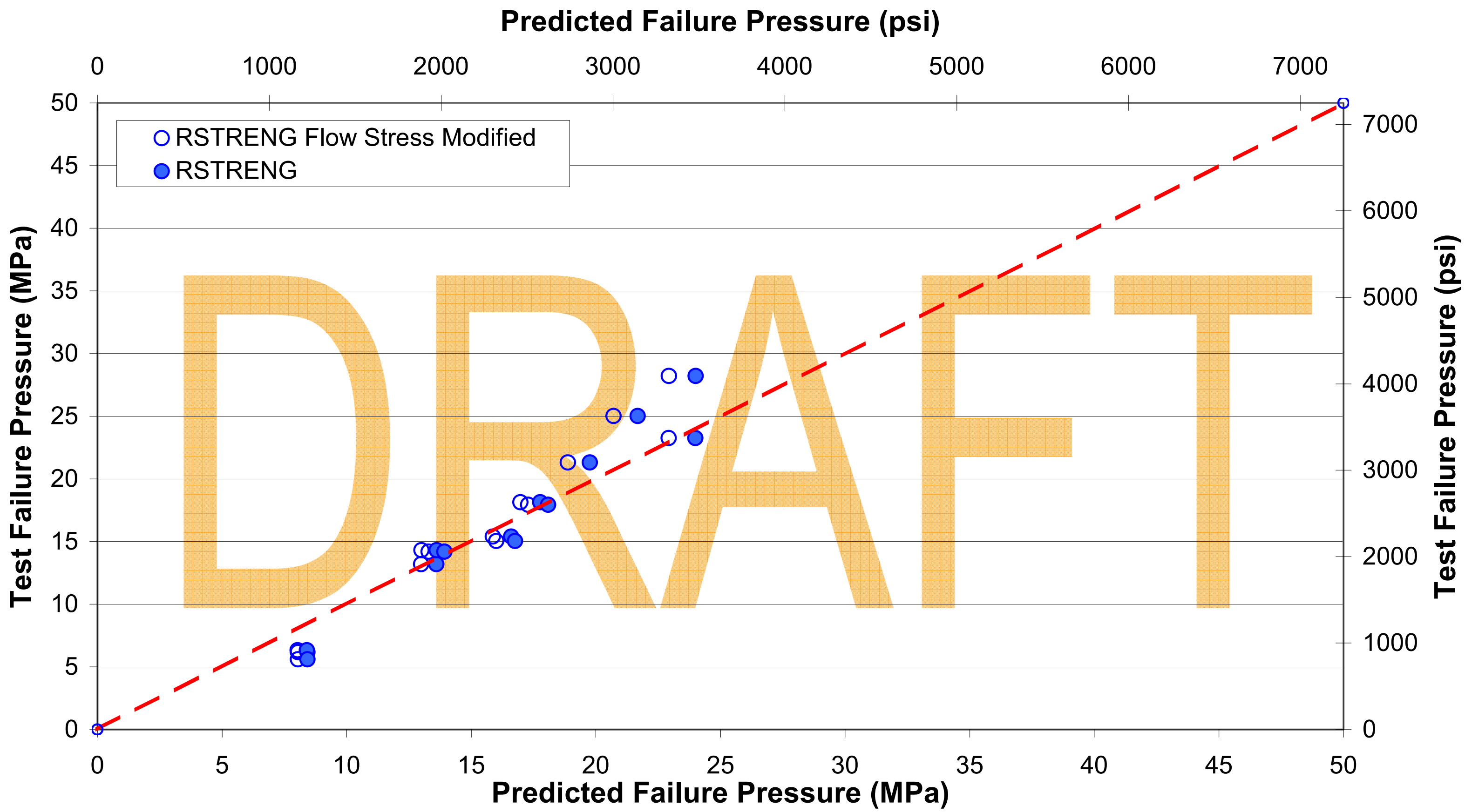


Figure 19 52-inch Diameter Grade X100 Line Pipe. Test versus RSTRENG Failure Pressures

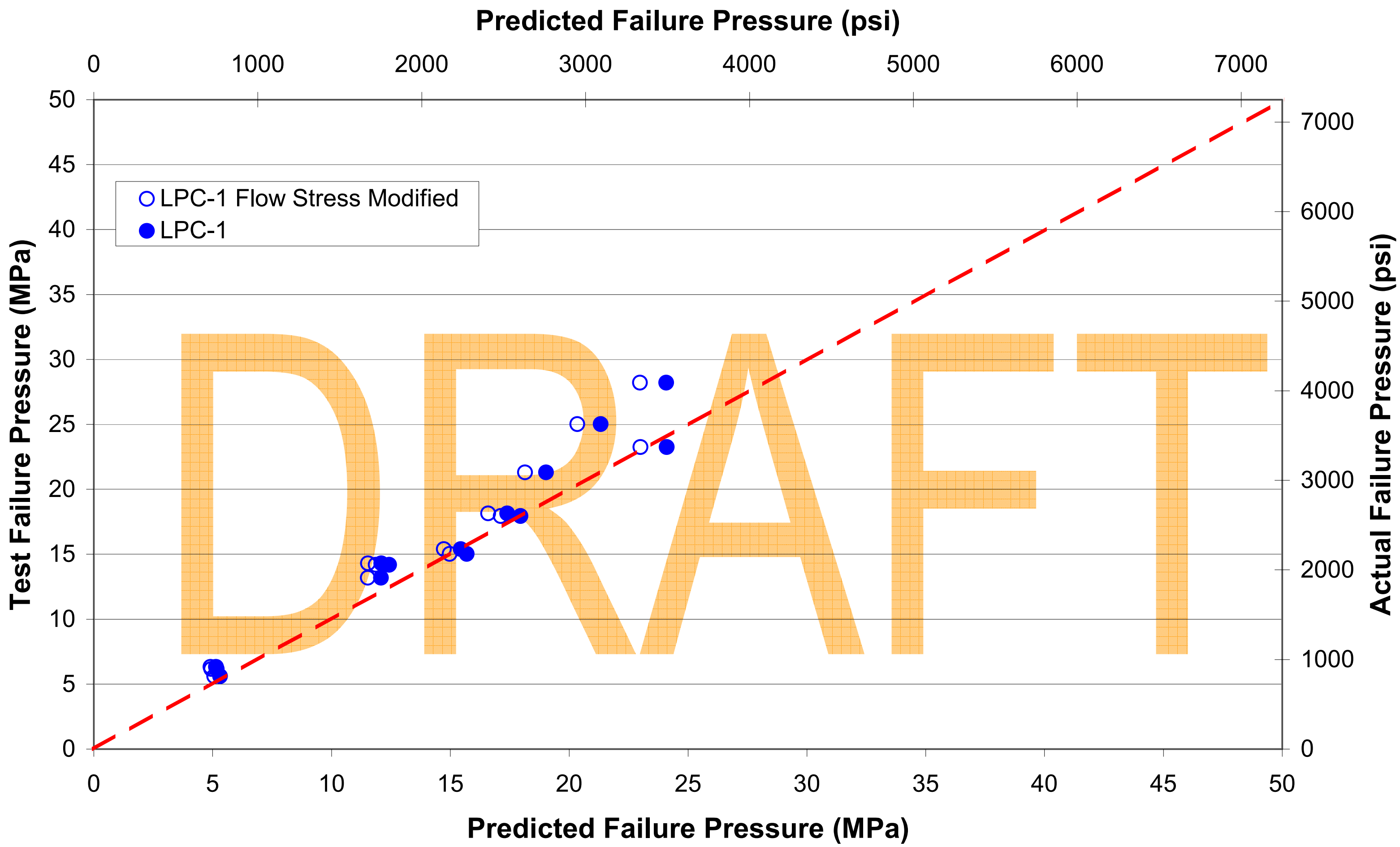


Figure 20 52-inch Diameter Grade X100 Line Pipe. Test versus LPC-1 Failure Pressures

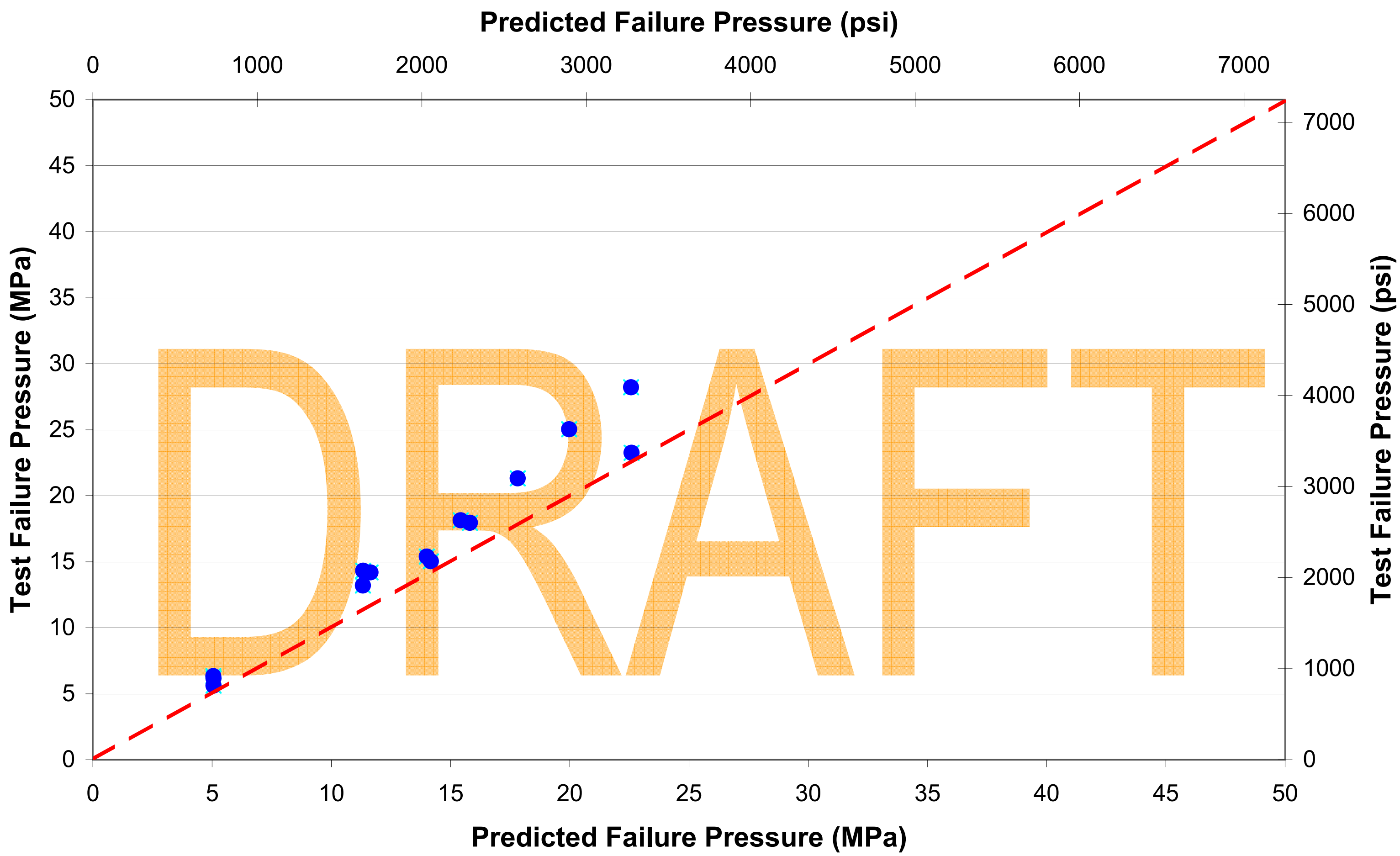


Figure 21 52-inch Diameter Grade X100 Line Pipe. Test versus Battelle-Shannon Predicted Failure Pressures